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Volume

1

CANADIAN PETROLEUM ASSOCIATION

1991 PIPELINE CONFERENCE
"PIPELINES IN A CHANGING ENVIRONMENT"
VOLUME 1

92-02766/

1991 CPA PIPELINE CONFERENCE:
PIPELINES IN A CHANGING ENVIRONMENT
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PIPELINE PERFORMANCE IN ALBERTA

A. CASSLEY, P. ENG.
PIPELINE DEPARTMENT
ENERGY RESOURCES CONSERVATION BOARD

CPA PIPELINE CONFERENCE
CALGARY - MAY 1991

PIPELINE PERFORMANCE IN ALBERTA

A. Introduction

The intent of this short presentation is to provide a summary of the ERCB's pipeline failure statistics. Enough background material is included to put the statistics in context with the development of the pipeline infrastructure in Alberta.

The presentation will cover four areas:

- background to the Alberta pipeline system,
- failure summaries by substance and by cause,
- failure rates in terms of failures per 1000 km, and
- distribution of volumes spilled.

DEFINITION

For the purposes of this presentation a pipeline failure is defined as the inability of the pipeline to contain the fluid being transported.

B. Background

1. Historical Development

Table 1 shows the major development of the Alberta system, starting with the Bow Island to Calgary gas pipeline in 1912.

TABLE 1

1912	CWNG Bow Island to Calgary	Gas
1920's	Royalite, Turner Valley NUL, Viking - Edmonton	Oil Gas
1940's	Imperial, Leduc - Nisku - Edmonton	Oil
1950's	Imperial, Devon - Edmonton Pembina, Edmonton Texaco, Wizard Lake - Edmonton Nisku Products, Devon to Edmonton Cremona, Harmattan - Calgary Peace River Oil, Sturgeon Lake - Edson North Canadian Oils, Wabamum - Hinton Alberta Gas Trunk Line, Plains Division Rangeland, Sundre - Rimbey Federated, Swan Hills - Edmonton Canadian Gulf, Fenn/Big Valley - Edmonton	Oil Oil Oil Products Oil Oil Gas Gas Oil Oil Oil

1960's	Expansion on the 1950's development Rainbow, Rainbow Lake - Edmonton Bow River, Taber - Hardisty	 Oil Oil
1970's	Dome, Ethane gathering APPL, Edmonton - Calgary AGEC, Joffre - Edmonton AOSP, Ft. McMurray - Edmonton Simmons, LacLaBiche - Ft. McMurray	Ethane Products Ethylene Oil Gas
1980's	AEC, Cold Lake - Edmonton Imperial, Ellerslie - Sundre	Diluent Bitumen-blend Bitumen-blend

The annual growth through the 70's and 80's has averaged about 8,000 km per year. The growth over the last 8 years is shown in Table 2.

TABLE 2

LENGTH OF PIPELINES IN ALBERTA
UNDER ERCB JURISDICTION

TYPE OF PIPELINE CUMULATIVE LENGTH (KM)

	(1983)	(1984)	(1985)	(1986)	(1987)	(1988)	(1989)	(1990)
CRUDE OIL	22 700	23 200	24 900	25 600	26 100	26 400	26 800	27 100
NATURAL GAS	95 500	105 000	106 000	110 200	113 400	117 000	120 800	125 500
SOUR GAS	3 000	3 500	4 000	4 400	4 600	5 100	5 400	5 700
WATER	12 900	13 500	14 300	15 000	15 600	16 000	16 400	16 700
MULTIPHASE	19 700	22 500	24 400	26 000	27 300	28 800	30 300	31 500
OTHERS*				600	1 000	1 300	1 600	1 700
TOTAL	153 800	163 200	173 600	181 800	188 000	194 600	201 300	208 200

* The "other" category for 1983 through 1986 was grouped with the water lines.

The table points out one of the difficulties the ERCB has with the data base. The development of HVP products pipelines did not commence until the late seventies, and so the HVP category was not necessary until then. These pipelines were lumped in with oil in some cases and with the water category (a catch-all category in those days) in others. Therefore the growth rate of HVP pipelines is not available, and the failure frequency in section E cannot be calculated. From other sources the current length of HVP pipelines has been calculated at about 6500 km. When the ERCB computerized its application process, classifying into the new categories has caused some inaccuracies. The absolute numbers quoted in Table 2 should therefore be treated as reasonable approximations. For identifying trends they are adequate.

A characteristic of the Alberta system which should be kept in mind when reviewing the failure statistics, is that about 70% of the pipelines are less than 150 mm diameter (NPS 6) and about 25% between 150 and 450 mm diameter (NPS 6 to NPS 16).

2. The Legislation

The legislation with respect to leak reporting is very specific and requires that all leaks or breaks be reported to the ERCB, including failures under test, with no limitations as to volume, cause or consequence. The requirements are stated in the Pipeline Act (Section 36) and the Pipeline Regulation (Sections 31 and 55).

3. Inspection

The Board maintains 8 Area Offices around the Province with at least one pipeline inspector in each office (see Appendix 1).

The Pipeline Department, in the Head Office, sets inspection objectives based in part on the failure record, with emphasis on sour gas and HVP pipelines. All failures on the latter two categories are required to be site-investigated.

4. Sources of data

The major source of data is the inspector's report which is required for all failures and is submitted on a standard form (known as the "F4", see Appendix 2). The data on the form includes pertinent pipeline information, location, estimated volume, environmental concerns and a brief description of cause and effect. The data is handled as part of the ERCB's Environmental Information System (EIS), which is a mainframe system.

Additional material may be added to the file from investigative reports required by the Board, e.g. metallurgical reports.

C. Failures Categorized by Substance Transported

There are 22 different substances defined in the system. For the purposes of analysis these are condensed into six categories:

Water	Sour Gas (10 mol/kmol)
Multiphase	Natural Gas
Crude Oil	HVP

Figure 1 shows the failure record for 11 years of the different substances. The failures include those occurring when a pipeline is under a pressure re-test following a repair or maintenance. These re-test failures are allocated to the substance licensed to be carried, even though most pressure tests are conducted with water. Operational failures are classified according to the substance which escapes, so that if the line is batching products, only one of the products would be counted.

Figure 2 shows the failure record of operational pipelines which more closely reflects actual failure history, and which is more meaningful when considering follow-up action and for analysis.

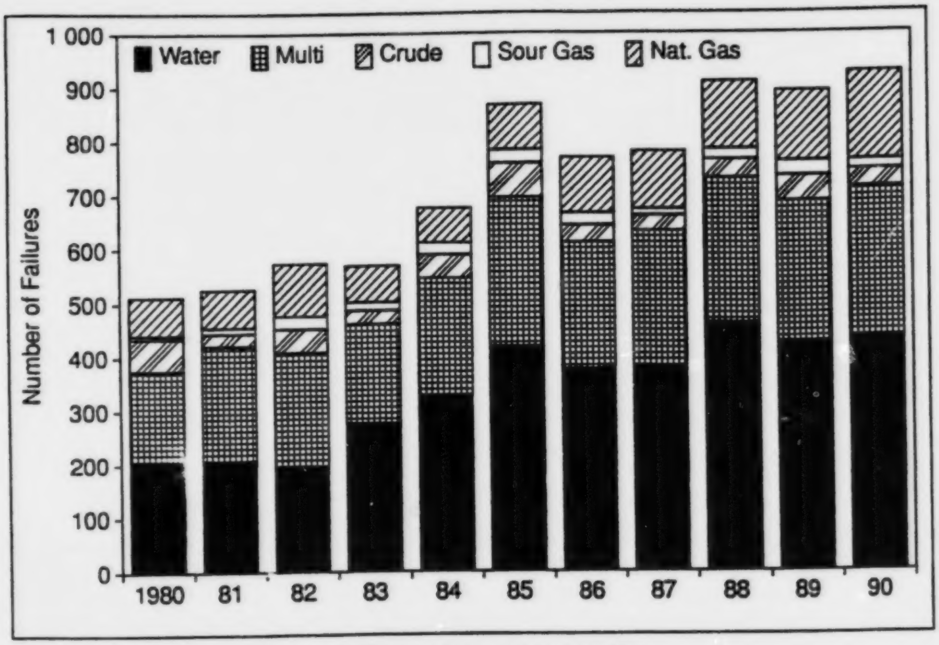


FIGURE 1 ANNUAL PIPELINE FAILURES
(Including Pressure Re-testing Failures)

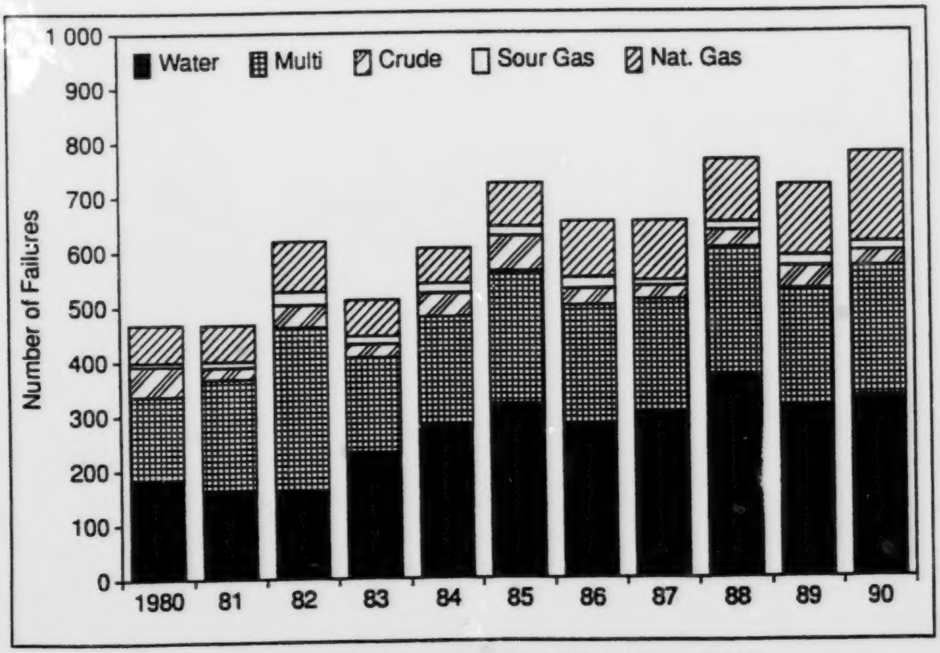


FIGURE 2 OPERATIONAL PIPELINE FAILURES

There have been less than 20 failures in 11 years on HVP pipelines, therefore they do not show up on these figures.

The figures show an upward trend in the numbers of failures, and that over the past five years of so there are about 700 annually. By far the great majority of these failures are on water and multiphase lines, which are usually small diameter pipelines. The apparently upward trend should be viewed in the light of the increasing length of operating pipelines (see Section E).

The remainder of the analysis is based on operational failures.

D. Failures Categorized by Cause

There are 18 failure causes defined in the system. For the purposes of this analysis these are condensed into six causes:

1.	Corrosion,	which includes Internal Corrosion, Corrosion at Girth or Fillet Weld, and External Corrosion.
2.	External Forces,	which includes Construction Damage, Damage by others, and Earth Movement.
3.	Weld,	which includes Girth Weld, other welds, and seam rupture.
4.	Equipment,	which includes Installation failure and Valve/Fitting failure.
5.	Joints,	which includes Mechanical Joints and Miscellaneous Joints.
6.	Other,	which includes Pipe body failure, overpressure, operator error, miscellaneous, unknown.

Figure 3 shows the distribution of failure causes for all pipelines.

Figure 4 shows the cause breakdown of five of the six substances. HVP is excluded because the low numbers of failures in this category make the percentages meaningless.

The main causes of failures are corrosion and third party damage. As would be expected, corrosion causes most failures in the pipelines transmitting aggressive fluids, such as multiphase oil well effluent, produced water and sour gas.

E. Frequency of Failures

Although the absolute numbers of failures gives useful information an analysis based on a unit of length is better for examining trends.

This can be done in a number of ways but perhaps the most meaningful for comparison purposes is to divide the cumulative number of failures for a substance category by the cumulative length of the pipelines for that category as in Figure 5. If a pipeline transports more than one category then its length is recorded according to a priority ordering. The priorities range from priority 1 for sour gas to priority 11 for fresh water.

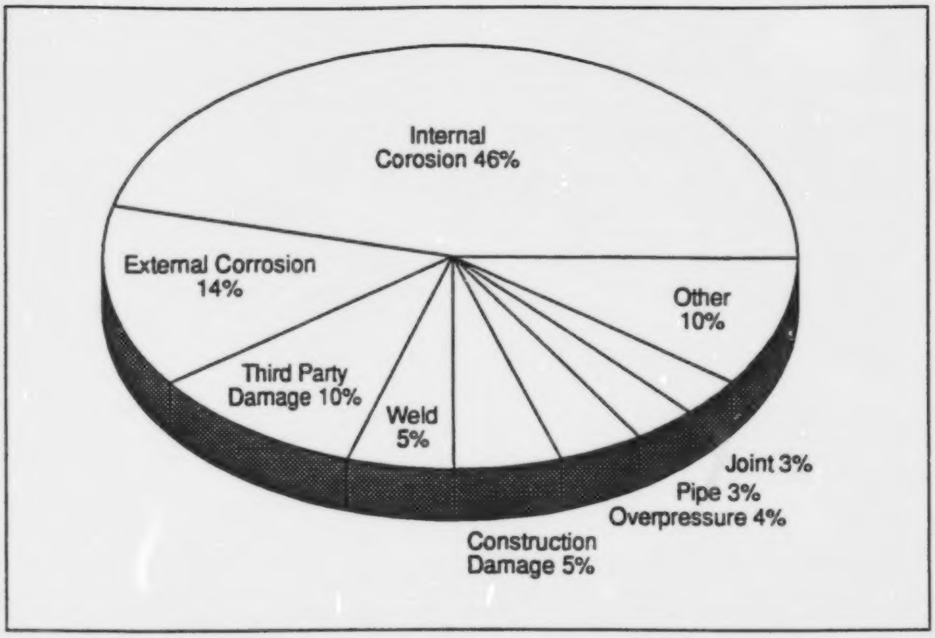


FIGURE 3 DISTRIBUTION OF FAILURE BY CAUSE
(Per Cent)

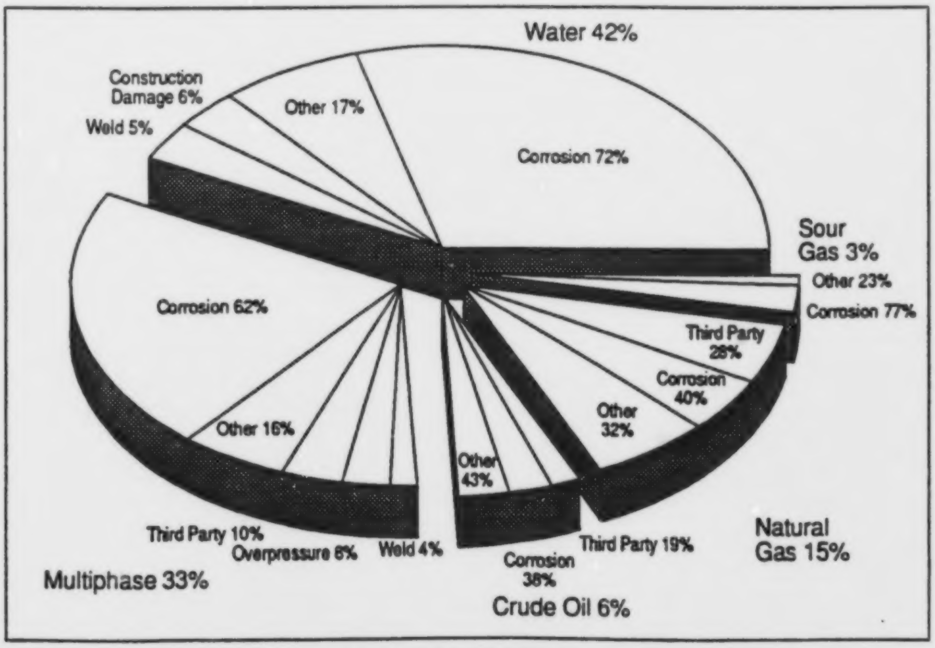


FIGURE 4 MAIN CAUSES OF PIPELINE FAILURES
By Pipeline Type (Per Cent)

These data show that the failure rate in general has remained constant, even though the infrastructure is growing and aging, with the exception of water and multiphase lines.

To focus on the variability from year to year the annual failures can be divided by the cumulative length to that year to give a failure rate of failures per 1000 km per year as in Figure 6.

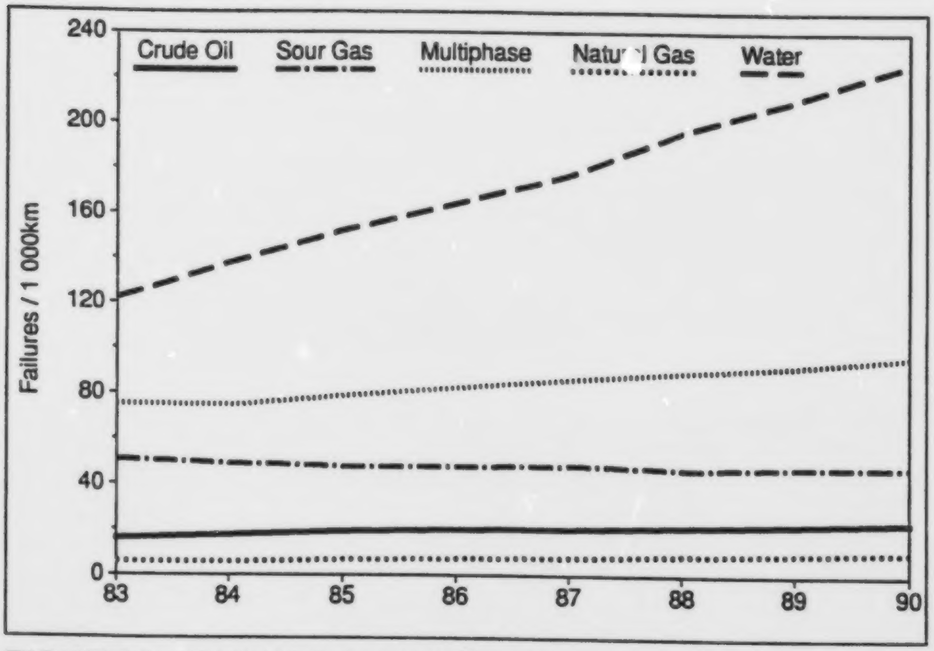


FIGURE 5 FAILURE FREQUENCY
(Based on Cumulative Substance Length and Cumulative Failures)

F. Leaks and Ruptures

Figure 7 shows that over 80 per cent of failures are leaks and less than 20 per cent ruptures.

- A leak is defined as a small opening or crack in the pipeline causing some product loss but not immediately impairing the operation of the line.
- A rupture is the instantaneous tearing or fracturing of the pipe material causing immediate impairment of the operation of the pipeline

The data show that most leaks are corrosion related and that a significant number of the ruptures are caused by third party damage.

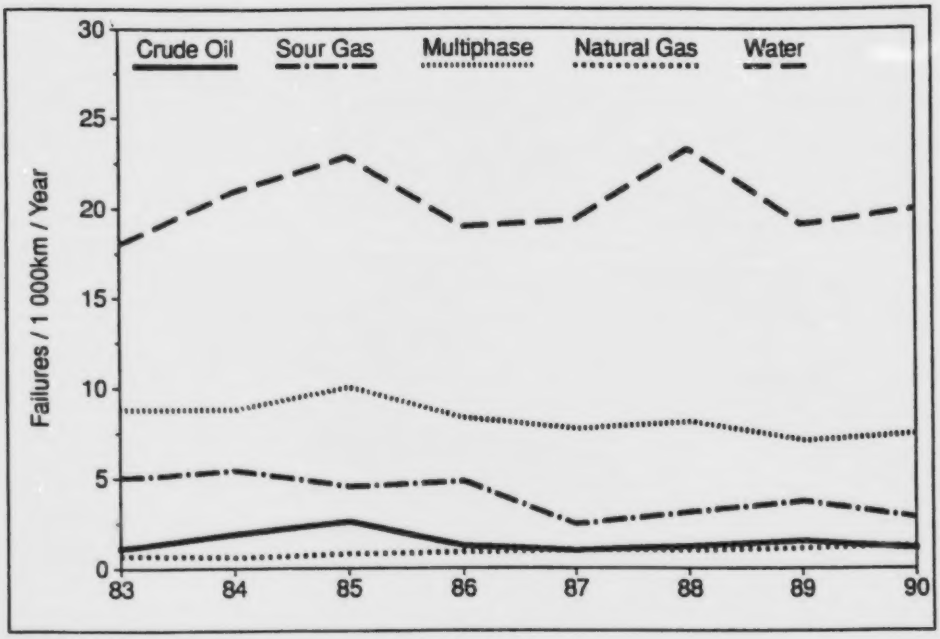


FIGURE 6 FAILURE FREQUENCY
(Based on Cumulative Pipeline Length and Annual Failures)

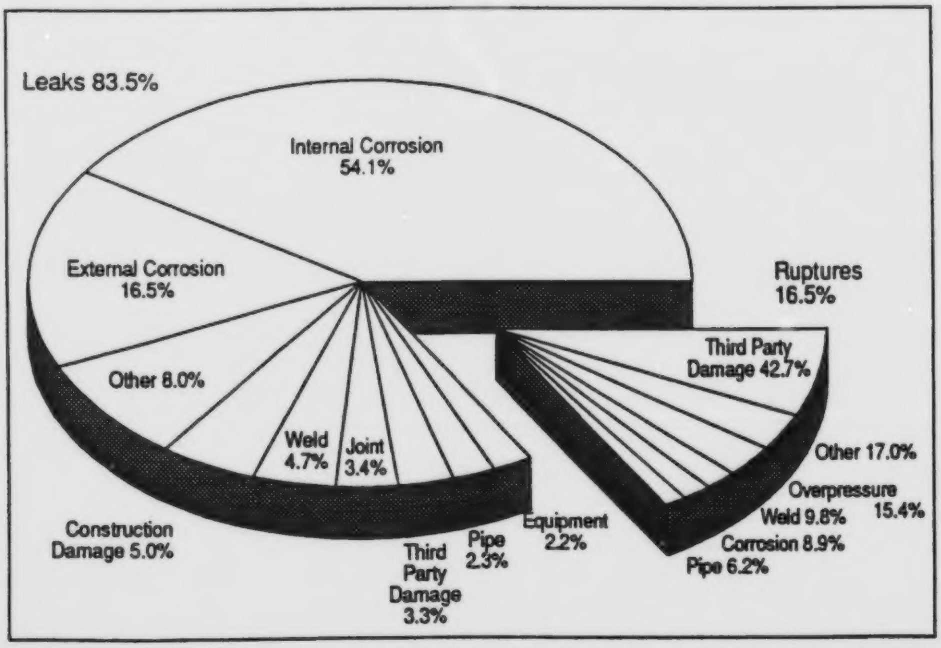


FIGURE 7 CAUSES OF PIPELINE LEAKS AND RUPTURES
(Per Cent)

G. Volumes Spilled

The analysis of volumes spilled is very approximate, because of the way the volumes are reported. The volumes are usually on-the-spot estimates, either by the Board inspector or company personnel. The distribution of liquid spill volumes over the last 11 years is shown in Table 3, and shows that the majority of spills are less than $5m^3$.

TABLE 3
DISTRIBUTION OF VOLUMES OF LIQUID SPILLS (%)

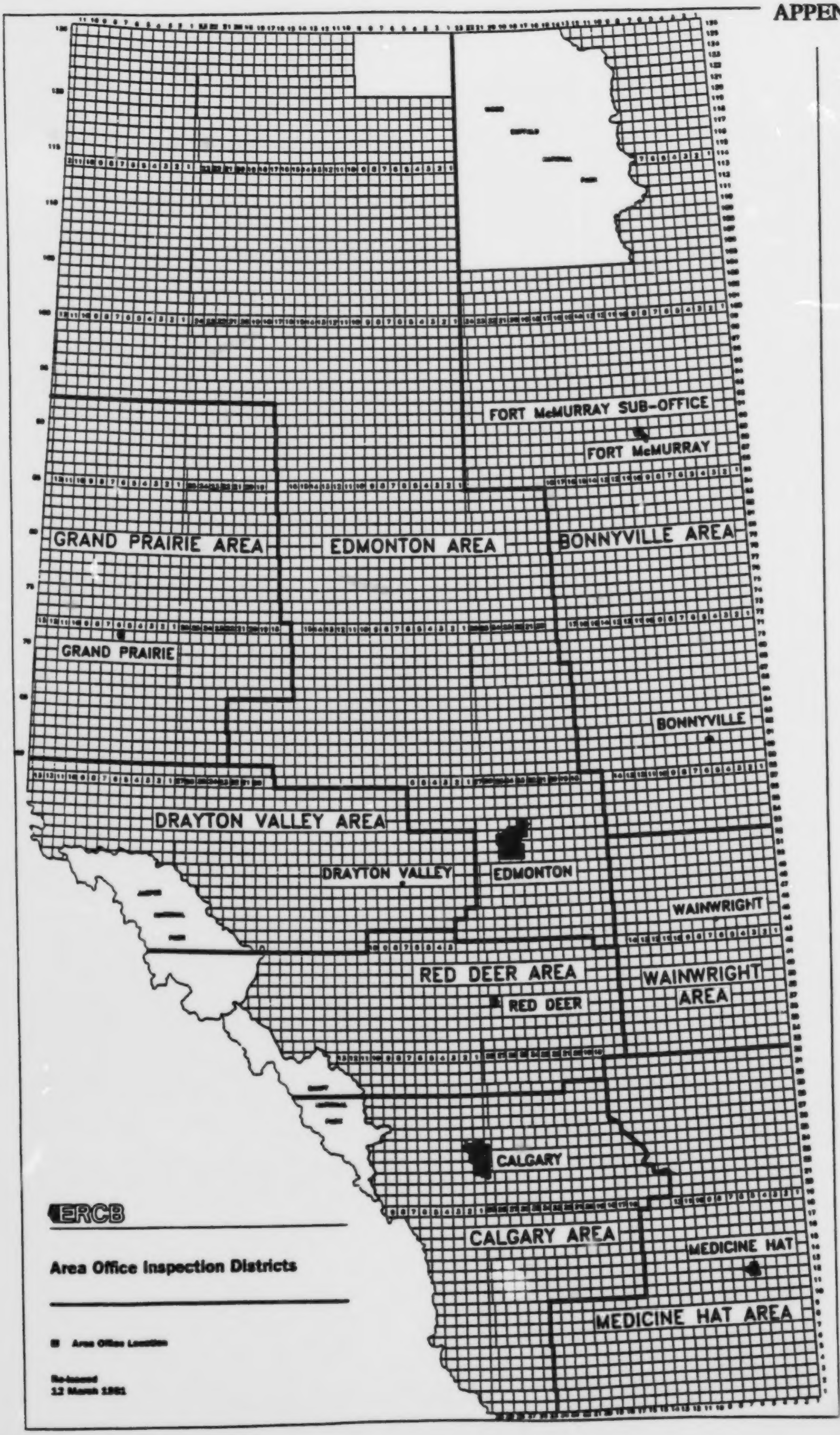
VOLUME (m^3)	WATER	MULTIPHASE	CRUDE OIL
Up to 1	30	38	42
1 < = 5	23	36	22
5 < = 10	12	8	7
10 < = 50	22	12	14
50 < = 100	7	3	6
100 < = 500	4	2	5
500 < = 1000	1	(0.3)	2
> 1000	1	0	1

H. Conclusions

The data shows that in the last 11 years:

- the distribution of causes of failures has not changed significantly,
- corrosion is the major cause of failure,
- the failure rate (failures per 1 000 km) has remained relatively constant,
- the anomaly is the increasing failure rate of water lines, and
- the large majority of failures are leaks not ruptures.

APPENDIX 1


FORT McMURRAY SUB-OFFICE
FORT McMURRAY
GRAND PRAIRIE AREA
EDMONTON AREA
BONNYVILLE AREA
GRAND PRAIRIE
BONNYVILLE
DRAYTON VALLEY AREA
DRAYTON VALLEY
EDMONTON
WAINWRIGHT
RED DEER AREA
RED DEER
WAINWRIGHT AREA
CALGARY
CALGARY AREA
MEDICINE HAT
MEDICINE HAT AREA
ERCB

Area Office Inspection Districts

■ Area Office Location

Re-issued
12 March 1981

ERCB

Energy Resources
Conservation Board
640 Fifth Avenue SW
Calgary, Alta. T2P 3G4

APPENDIX 2

POLLUTION/BREAK RECORD

A.C.D CODE ☐ 80

LOCATION OF SOURCE: LE | LS | SC | TWP | RG | W | M (11, 12)

EVENT (13 14)

CARD 0 8 0 (15 17)

DATE/TIME OF OCCURRENCE: YR. | MO. | DAY | HR | MIN (18, 23)

DATE/TIME REPORT RECEIVED: YR | MO | DAY | HR | MIN

COMPLAINT ☐ 24

REPORT ☐ 25

SOURCE/CAUSE (26, 29)

INJURY ☐ 30

DEATH ☐ 31

AREA OFFICE (32 33)

FOREST DISTRICT (34 35)

FIELD OR AREA (36, 39)

COMPLAINANT OR REPORTER | ADDRESS | PHONE | INTERVIEW DATE: YR | MO | DAY

OPERATOR OR LICENSEE (40, 43) | ADDRESS (44) | PHONE | INTERVIEW DATE: YR | MO | DAY

PIPELINE FAILURE INFORMATION

LICENCE NO (45, 50)

LINE NO (51, 53)

INSTAL NO (54, 55)

LEAK OR RUPTURE L/R ☐ 56

TEST FAILURE T ☐ 57

OPER PRES AT TIME & LOC. OF FAILURE (kPa)

M.O.P. (kPa)

(58, 65)

LINE O.D. (mm) (66, 70)

PIPE TYPE/SPECIFICATION

GRADE (71, 74)

WALL TH (mm) (75, 78)

COVER (cm) ± 10 cm

EXTERNAL COATING Y ☐ N ☐

INTERNAL COATING Y ☐ N ☐

CATHODIC PROTECTION Y ☐ N ☐

INT CORROSION PREVENTION Y ☐ N ☐

TYPE

REPAIR LENGTH (m)

PRETEST PIPE Y ☐ N ☐

RETEST Y ☐ N ☐

PROPOSED ☐

ACTUAL ☐

TEST PRES (kPa) | DUR (hr) | TEST MEDIUM

GAS DISCHARGE (10^3m^3): CARD 0 9 0 (15, 17) | SWEET SOUR (24) | VOLUME (29)

WATER OR WATER BASE MATERIAL (m^3): DESCRIPTION (30) | DISCHARGE | RECOVERED (40)

LIQUID HYDROCARBONS (m^3): DESCRIPTION (41) | DISCHARGE | RECOVERED (51)

LIQUID SPILLS

CONTAINED ON LEASE? YES 1 (52) NO 2 (52)

TERRAIN AFFECTED: LAND 1 (59) WATER 2 (59) BOTH 3 (59)

REHABILITATION REQUIRED? YES 1 (66) NO 2 (66)

DESCRIBE EXTENT OF SPILL

CLEAN UP COMP: YR | MO | DAY (53, 58)

NEXT SCHED INSP: YR | MO | DAY (60, 65)

REHAB COMPLETE: YR | MO. | DAY (67, 72)

NOISE ☐ 73

ODOUR ☐ 74

SMOKE ☐ 75

REMARKS

INDICATE INTENSITY OF POLLUTANT, CONTINUOUS OR INTERMITTENT - EFFECT OF OCCURRENCE ON HUMANS, LIVESTOCK, CROPS ETC.
DESCRIBE PIPELINE FAILURE, CAUSE ETC.
LIST ACTION REQUIRED —

GOVERNMENT DEPT. NOTIFIED

DEPARTMENT		DATE YR	MO	DAY
	76			
	77			
	78			
	79			
A. C. D CODE	80			

STEAM THAWING OF FROZEN GROUND

P.A. (Pete) Poohkay, P. Eng., P. Ag., and B.M. (Blain) Smetaniuk, P. Eng.

Excavation of frozen ground to uncover underground power and gas lines can be a dangerous and costly operation without the aid of a practical, safe, and economical method of ground thawing.

It has long been accepted for the utility industry in Alberta to burn coal during the winter to thaw frozen ground for most excavations. Currently, the Alberta Government imposes virtually no restrictions on those whom employ the open coal burning technique. However, some municipalities have disallowed this practise due to concerns regarding the fire hazard and environmental impact.

To address this situation, Northwestern Utilities Limited (NUL) evaluated three ground thawing techniques, two methods operating on the same principle, applying heat to the surface of the ground, the third involving steam injection. Field testing of the ground heaters provided inconsistent results with regard to achieving adequate depth of thaw. A crucial operation in pipeline construction is exposing existing utilities by hand, therefore it is imperative that the "Pipe Zone" is completely thawed. Other issues that were considered included public safety, convenience of operation, performance and environmental impact.

Since the winter of 1988 - 1989, NUL Construction Department have been testing the use of steam injection to thaw frozen ground. NUL has developed a ground thawing steamer that has provided excellent results and has proven to be the best option for NUL's purposes.

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STEAM THAWING OF FROZEN GROUND

P.A. (Pete) Poohkay, P. Eng., P. Ag., and B.M. (Blain) Smetaniuk, P. Eng.

ABSTRACT

Excavation of frozen ground to uncover underground power and gas lines can be a dangerous and costly operation without the aid of a practical, safe, and economical method of ground thawing.

It has long been accepted for the utility industry in Alberta to burn coal during the winter to thaw frozen ground for most excavations. Currently, the Alberta Government imposes virtually no restrictions on those whom employ the open coal burning technique. However, some municipalities have disallowed this practise due to concerns regarding the fire hazard and environmental impact.

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INTRODUCTION

Ground frost ranks high on the list of problems that Northwestern Utilities Limited (NUL) construction crews have to overcome during winter construction. The soil freezes some time late in November and remains frozen until mid April in the Edmonton area. With frost depths averaging four feet and frozen soils possessing compressive strengths approaching that of hard wood, excavation to uncover underground power and gas lines can be a dangerous and costly operation. Excavation tends to be hard on equipment and manpower. Special frost buckets are used on excavators, and jackhammers, both hand operated and excavator mounted, are used to break the frozen ground to aid in soil removal.

Traditionally, NUL has used the open coal burning technique to thaw frozen ground prior to excavation. A quantity of subbituminous coal is spread over the excavation area and burned over a period of days. The coal burns in a smoldering fashion and the rate of combustion varies somewhat with ambient conditions. High wind velocity tends to speed the burning rate while snowfall and water run-off slows the process. During the burning process the site is left barricaded and unattended providing a fire hazard as hot airborne cinders can be carried into adjacent combustible materials. In addition to the fire hazard, public inconveniences result due to offensive odors, blowing smoke and residual ash. Typically the "tie-in bell hole" and utility line crossing sites are thawed to ensure digging does not damage the utility lines. In all cases the existing utility is "hand exposed" to eliminate any chances of hitting the utility with power machinery which could result in a dangerous and costly situation. Since hand exposure is performed it is imperative that the ground is thawed at the "pipe zone" or depth of burial (typically 1.2m).

In early spring when the ambient temperatures are above 0°C and the top few centimeters of soil are thawing, the coal fire ground heating technique becomes less effective. The heat does not penetrate the soil as readily as it does in cold weather, rather it tends to radiate out from the fire at ground level. The surrounding snow and ice (already melting) is further melted creating water run off which extinguish the coal fire. This is an annual problem, occurring when the frost is at its greatest depth and when the new construction season begins.

As a result of recent concerns regarding the fire hazard, environmental impact (which have led some municipalities into banning the thawing technique) and the spring time thawing problems with the coal burning technique, Northwestern Utilities Limited has been forced to find an alternate ground thawing method. One that is effective and imposes as little danger to the public and environment as practicably possible.

ALTERNATIVES

In 1988, NUL evaluated two types of equipment designed to thaw ground. One system was fueled by diesel, the heat from the combustion flame was radiated onto the ground in the form of infrared energy. The burner consumed 18 liters of fuel per hour and was able to operate for 12 hours before requiring refuelling. The second system burned propane at a rate of 3.8 kg per hour requiring refuelling every 24 hours. The combustion gases from the burner were conducted through a piping system and heat from the piping system radiated onto the ground surface. Both systems, as with the coal fire, operated on the same principle - applying heat to the ground surface. After the heating operation was completed, the site was simply excavated as in the summer, in frost free conditions.

The ground surface heaters generated high ground surface temperatures, but the rate of heat penetration appeared to be limited. It was found that a minimum of 24 hours was required to soften the soil so that digging could take place, but in most cases 3 - 4 days was required to completely thaw the frost down to the "pipe zone". One problem that became clear which accounted for the slow rate of thaw, was the high heat requirements needed to boil off water which drained onto the site as the ice and snow melted. Heat from the heater was absorbed as latent heat of vaporization while boiling off ground surface water, rather than penetrating the frozen soil.

To better understand these limitations, NUL consulted a report provided by the City of Calgary which dealt with the ground thawing process. In 1985, EBA Engineering Consultants Ltd., in conjunction with Canadian Western Natural Gas Company Ltd., City of Calgary, Alberta Government Telephones Company, and Rogers Cable TV Ltd. undertook the task of studying the ground thawing process during the application of heat to the ground surface. Coal fires, propane burners, and electric heaters were used to generate heat. A variety of ground surface temperatures and heating times were used to evaluate the thawing effect. The study resulted in the following conclusions:

- The rate of thaw (penetration of heat) was temperature limited. Raising the ground surface temperature above 100°C did not significantly increase the rate of thaw. When the soil was heated to a temperature above 100°C, the soil rapidly dried forming a layer of soil with a higher thermal resistance than would otherwise be the case if it remained wet. This insulating layer impeded further heat transfer slowing the rate of thaw (see fig. 1).

- The optimum rate of thaw (average ground surface temperature of 100°C) resulted in a 1.25m depth of thaw in a typical clay-till soil (Calgary, Alberta) to be achieved after approximately 96 hours of heating.

The ground heaters evaluated by NUL, imposed their own version of public dangers as the equipment required relatively long operating times and had to be left unattended with only barricades separating hot equipment parts (1300°C) and inquisitive passers-by. Mechanical breakdowns, refuelling requirements, and vandalism all appeared to be a potential for failure to fulfill the ground heating requirements. These problems seemed highly probable which would result in operational difficulties. Public inconveniences due to traffic interruptions and imposing equipment were also considered major drawbacks.

During that same year, NUL learned of an alternative used by the Enstar Gas Company - Anchorage, Alaska. The technique involved the injection of steam into the frozen ground to create the thawing effect.

Steam generated in a high pressure boiler was conducted onto the work site and injected into the ground that would be eventually excavated. NUL experimented with rented boilers and tried a variety of injection configurations. Injection probes fabricated from pipe (ends closed) with steam outlet holes drilled along the length of the probe were initially tried. The ground required to be pre-drilled to allow for probe insertion. This configuration resulted in poor steam penetration since a large portion of the steam easily made its way up the insertion hole. The best injector design proved to be one that possessed a single outlet hole drilled in a weld cap at the end of the probe (see fig. 2). The force of the steam flow from the probe would erode a hole into the soil with little applied force to the probe, therefore eliminating predrilling the soil. The probes took 5 to 10 minutes to penetrate to a maximum depth of 1.3m. The thawing mechanism was investigated by injecting various amounts of steam into a variety of soils and excavating the sites after allowing the soils to thaw for different lengths of time.

During the injection phase (see fig. 3) the steam created a thawed pocket of soil within the frost zone, or in the case where the frost layer was relatively thin (1.3m or less) the steam was injected into the unfrozen soil under the frost zone. Injection times varied from 1 1/2 hours in loose soils to 3 hours in hard and compact soils. The steam condensed, resulting in heat stored in pockets of hot, water saturated soil.

During the thawing phase (see fig. 3), heat was transferred from the saturated soil into the adjacent frozen soil. The soil thawed and absorbed the injected water. Ultimately the frost zone was completely thawed within a 1m radius of the injector. The thawing process took 24 hours in loamy soils and 48 hours in dense cohesive clays. The soil remained thawed for several days even in the coldest weather. If the site was to be left for more than 3 days in weather where the ambient temperature was below -25°C, straw bales were used to cover the site and insulate the ground, therefore preventing refreezing of the top layer of soil. After a full 48 hour "soak", the soil sufficiently absorbed the injected water (originally steam) to the extent where the excavated soil resembled that found in the summer. Virtually any soil could be thawed including roadway material, fillcrete, gravel, and sands. Thawing under asphalt and concrete was done with excellent results, although requiring pre-drilled holes for probe insertion.

The injected steam was delivered to the injection probes at 930 kPa, 177°C and in the saturated state. Approximately 10% of the steam was lost to the atmosphere through injector leakage (blow back up injector probe hole). Typically 450 liters of water was injected into a tie-in bell hole site.

After evaluating the operational aspects of the various ground thawing techniques, the environmental impact issue required attention. Open burning coal was found to be far more aggressive on the environment than burning a hydrocarbon fuel in a burner when the same amount of feul energy was expended. The typical thawing requirement was evaluated (one in which a service tie-in site was prepared for excavation). To adequately thaw such a site, 180 kg of subbituminous coal was burned over a period of four days. The two ground surface heaters evaluated by NUL burned hydrocarbon fuels to generate heat, and required large quantities of fuel to completely thaw to depths of 1.25m. One system required 860 liters of diesel and the other 180 kg of propane. These figures were based on a two day operation time. Using a boiler to generate enough steam to thaw a similar site required 75 liters of diesel or $70m^3$ of natural gas. Seven combustion by-products were compared to determine which method generated the lowest amounts of pollutants.

Figures 4 through 10 were generated from data presented in a report entitled "Compilation of Air Pollutant Emission Factors", report AP-42, fourth edition, September 1985, published by U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, 27711. The report summarized emission studies performed on a variety of hydrocarbon fuel burning systems and open coal burning. Although the data did not represent the ground heaters specifically, the information was considered adequate to provide a general idea of the pollutants emitted from similar equipment. The coal fire data represented the combustion of 180 kg of subbituminous coal burned in a hand stoked boiler where the coal is piled on gratework. This was the closest information available regarding open coal burning, and the emission values are probably better (lower) than what would be expected from a coal fire burning on the ground surface. The propane and diesel data represented 180 kg of propane and 860 liters of fuel oil burned in a small commercial burner as would be found in small commercial boilers or in the two ground surface heaters evaluated by NUL. A natural gas and diesel boiler burning $70m^3$ of natural gas and 75 liters of diesel respectively were compared to the other systems. The graphs presented compare the mass (kg) of pollutants expected to be produced when operating the above mentioned equipment and respective fuel quantities.

Fuel constituents along with the method of combustion determines what by-products can be expected from the burning of a fuel. The method of combustion sets the coal fire apart from the other systems which all incorporate a burner to achieve combustion.

The boilers and ground heaters burn hydrocarbon fuels in burners designed to oxidize as much of the carbon in the fuel as possible. As a result, low carbon monoxide emissions can be expected as compared to the coal fire which burns in an air deficient environment (the fuel is piled restricting air flow). This air deficiency results in an oxygen deficiency and enhances carbon monoxide formation. Nitrogen oxide formation in the coal pile is retarded since the air flow into the fire is minimal (air consists of approximately 70% nitrogen). In addition to the poor nitrogen supply, the coal fire temperatures are generally below that what is normally required to foster nitrogen oxide formation (above 1650°C). Therefore, the diesel fired ground heater could generate more nitrogen oxides than the coal fire due to the quantity of fuel consumed and nature of the combustion (most burners require excess air to achieve complete combustion which introduces higher quantities of nitrogen). Natural gas and propane are relatively "clean" fuels as compared to coal and diesel and diesel is considered much cleaner than coal. This refers to the amount of sulphur and particulates contained in the fuel. The diesel fired ground heater could generate more sulphur oxides than the coal fire as a result of the amount of the fuel burned, even though coal contains more sulphur than diesel.

Carbon dioxide formation is based on the chemical structure of the fuel and combustion environment. The heat of combustion of a hydrocarbon fuel theoretically comes from the oxidation of carbon and hydrogen. Natural gas possesses a lower carbon to hydrogen ratio than propane, diesel, or coal therefore, proportionally more heat comes from the oxidation of hydrogen (formation of water) than the oxidation of carbon (formation of carbon dioxide) during the combustion of natural gas. Coal has the highest carbon to hydrogen ratio, therefore generating the most carbon dioxide per unit of heat released as opposed to natural gas that produces the least. Propane and diesel fall in between natural gas and coal with regard to carbon to hydrogen ratios, with diesel producing more carbon dioxide than propane.

Evaluation of the data graphed in figures 4 through 10 proved that the method of thawing with the least relative impact on the environment from an emissions stand point was the steam injection system (regardless of the fuel used) due to the efficient use of the fuel.

STEAM - THE BETTER CHOICE

Four fundamental areas must be addressed when choosing which ground thawing system to use. These being, ***Safety***, ***Environmental Impact***, ***Economics,*** and ***Practicability.***

Steam thawing is by far the safest of all thawing techniques. The operation generally takes two hours to complete, supervised by qualified techniques. This short exposure time mitigates potential for injury to the public, unlike systems requiring several days of unattended use. The short operation time also reduces traffic interruptions (especially during the night) which can reduce potential traffic accidents, not to mention inconveniences. The combustion flame is confined to the boiler furnace eliminating any fire hazards unlike the ground surface heater that heats the ground to extreme temperatures, or the coal fire that can be spread by wind. Atmospheric conditions do not affect the safety characteristics of the steaming operation, high wind or snowfall does not interrupt the thawing process.

Steaming is also the "cleanest" method, introducing the least pollutants into the atmosphere. The efficient transfer of heat from the combustion flame to the frost is the key to this attribute. Typically 4200 MJ of energy was expended during the coal fire, 33,000 MJ with the diesel ground heater, and 9,000 MJ with the propane ground heater (based on a two day application). The diesel boiler and natural gas boiler expended 2,900 MJ and 2,600 MJ respectively, to generate the steam required to thaw a similar site, with the cleanest version being the natural gas steamer.

Since the objective was to find an alternative to coal burning, the cost to "fire" a site using coal was not a consideration. Coal burning costs considerable less than any other ground thawing technique and many sites can be started throughout an eight hour shift. Some sites may require maintenance such as relighting and at times the site may be "refired" if the first fire did not thaw to the appropriate depth.

The capital cost to construct a steamer is approximately three times that of a ground heater. If two days (48 hours) of heating time is required for a ground heater to adequately thaw a site, the equipment is unavailable for 48 hours. A steamer averaging four hours per site (including refuelling, replenishing water supplies, shift changes, and travelling) could conceivably steam 12 sites over a continuous 48 hour period. Typically three sites can be done in an eight hour shift. Therefore, from purely an operational standpoint (ignoring the required 24 go 48 hours "thawing phase" time for the steaming technique), the steamer could do 6 to 12 times the number of sites a ground heater might do. Factoring in wages, maintenance and fuel costs, the steaming technique costs less than half of the cost of operating a ground heater to do the same number of work sites.

Steam thawing provides excellent versatility with regard to conforming to unique site situations. The injection probes can be arranged in any pattern providing the ability to thaw around existing above and below ground facilities, operate in confined spaces and on uneven ground. The size or shape of the work sites is not limited to that of the thawing equipment as with the ground heating technique.

NUL'S STEAMER

During the winter of 1990, Northwestern Utilities Limited designed and constructed a self contained ground thawing unit.

The design revolved around the steam generation requirements and duration of operation. A fire tube type high pressure steam boiler was chosen to generate saturated steam. Electrical power for the boiler was supplied by an electric generator. Both the boiler and generator were fueled on diesel. The operating limit was set at three - eight hour days before refuelling or replenishing water supplies. Fuel and water requirements resulted in storage capacities of 750 liters and 5400 liters respectively. The unit was designed to tolerate ambient temperatures of -35°C, therefore requiring all the equipment, with the exception of the fuel storage tanks to be mounted within an insulated enclosure. With equipment weights totalling over 16000 kg, a single axle, insulated freight trailer was used to contain the steam generation equipment and the unit was pulled by a tandem axle tractor. The steamer unit was engineered to meet all applicable codes, standards, and OH & S requirements. The design and construction was approved by local government authorities to ensure safe and dependable operation. Two certified boiler operators operate the steamer working on an eight hour day basis.

Reception by NUL construction crews has been excellent resulting in a high demand for the thawing service. The injection operation is usually scheduled two days prior to the crew excavating the site. Due to the high thawing demands and excellent thawing results, a need for more steamer units became evident.

During the winter of 1991, NUL designed and constructed a natural gas fueled steamer which has become the prototype for all future units. The concept was identical to that of a diesel version with two exceptions. A tandem axle freight trailer has been used to permit the use of a single axle tractor which improves maneuverability and reduces the initial capital expenditure and future tractor maintenance costs. The second exception being the fuel system. Natural gas contained within 15 cylinders, with a total capacity of 460m^3 (at STP), stored at 20.7 MPa supply fuel to both the boiler and generator. The cylinders and fuel system were mounted inside the trailer and designed in accordance to the local "Natural Gas For Vehicles" codes and standards

CONCLUSION

Excavation of underground power and gas lines in frozen ground can be a dangerous and costly operation to a utility company without the aid of a practical and economical method of ground thawing. Northwestern Utilities Limited developed their own steam injection system as a proactive step towards finding an alternative to the use of coal burning. Steaming has been field proven to be an effective method of thawing ground and is safe in the course of its application. The process of transferring heat generated by the burning of a boiler fuel, such as natural gas, directly into the frozen ground is an efficient and environmentally friendly use of energy.

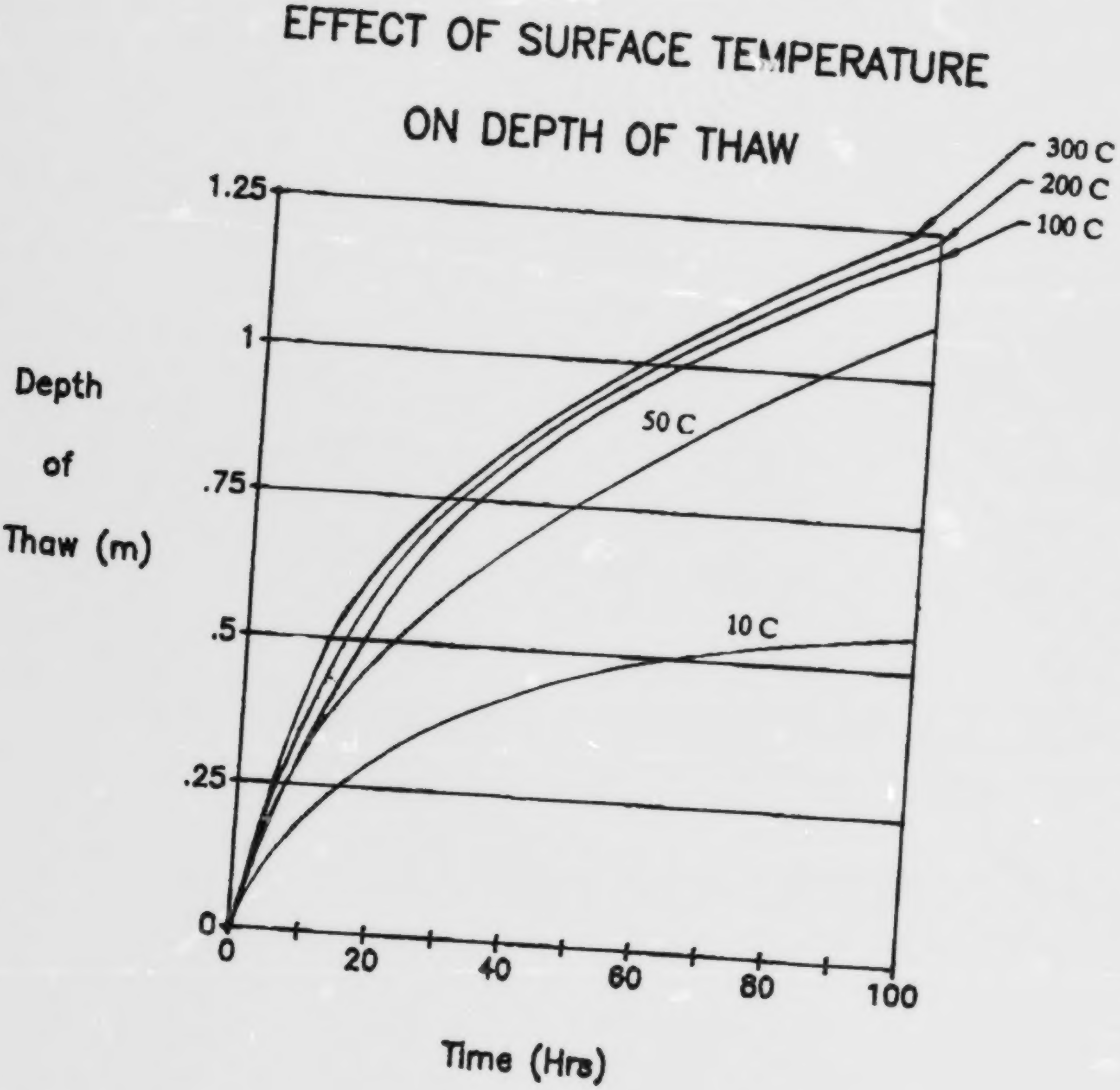
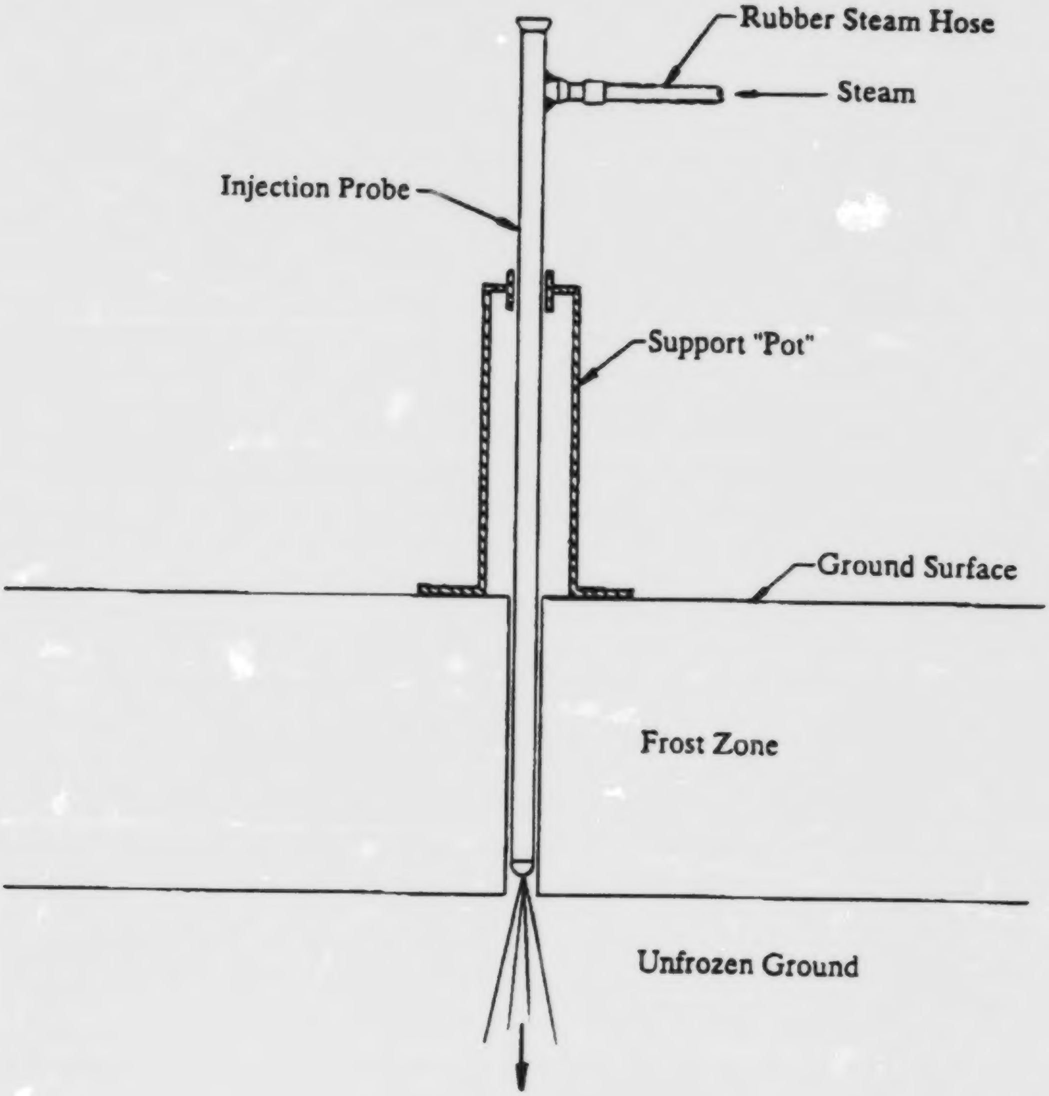

EFFECT OF SURFACE TEMPERATURE
ON DEPTH OF THAW
Depth of Thaw (m)
1.25
1
.75
.5
.25
0
0
20
40
60
80
100
Time (Hrs)
300 C
200 C
100 C
50 C
10 C

Figure 1

STEAM INJECTOR

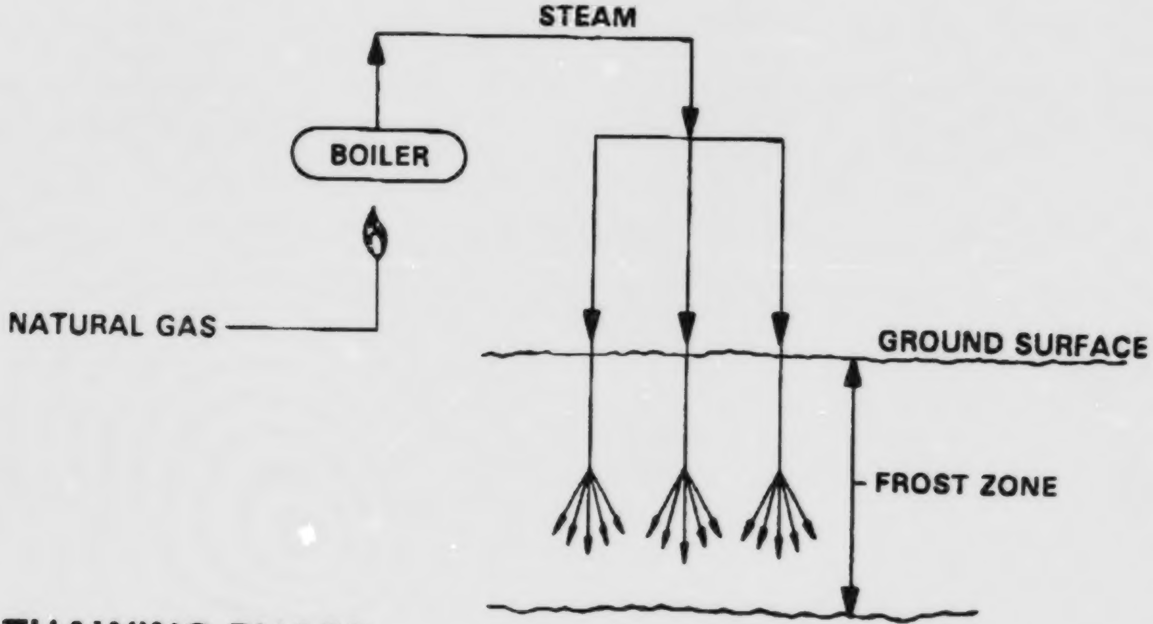

Rubber Steam Hose
Steam
Injection Probe
Support "Pot"
Ground Surface
Frost Zone
Unfrozen Ground

- Injection probe made up of pipe (ends closed) with a single steam outlet hole drilled in weld cap.
- Support "pot" functions to maintain injector probe in vertical position while probe penetrates soil and contains steam blow-by.

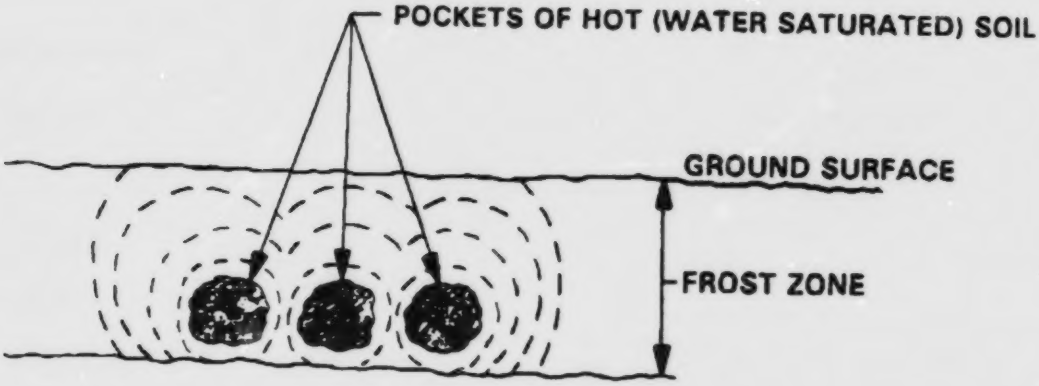
Figure 2

HOW IT WORKS

APPLICATION PHASE - TYPICAL APPLICATION TIME = 2 HOURS


STEAM
BOILER
NATURAL GAS
GROUND SURFACE
FROST ZONE

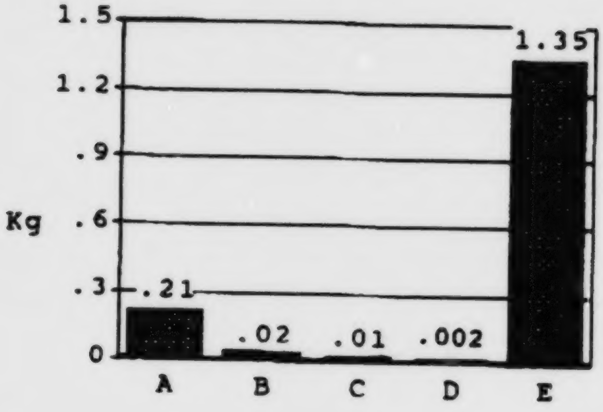
THAWING PHASE


POCKETS OF HOT (WATER SATURATED) SOIL
GROUND SURFACE
FROST ZONE

DURING THE THAWING PHASE, HEAT MOVES FROM THE HOT SATURATED SOIL INTO ADJACENT FROZEN SOIL. THE ADJACENT SOIL THAWS AND ABSORBS THE INJECTED WATER. FINALLY, THE ENTIRE FROST ZONE IS THAWED, AND THE INJECTED WATER (ORIGINALLY STEAM) IS ABSORBED THROUGHOUT THE "THAWED ZONE" RESULTING IN SOIL CONDITIONS SIMILAR TO THAT FOUND IN THE SUMMER.

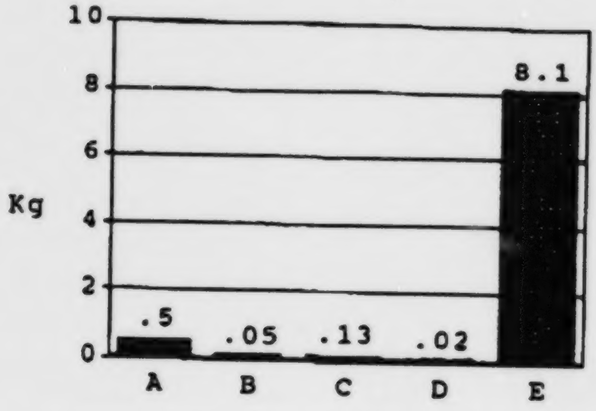
Figure 3

Emissions Comparison



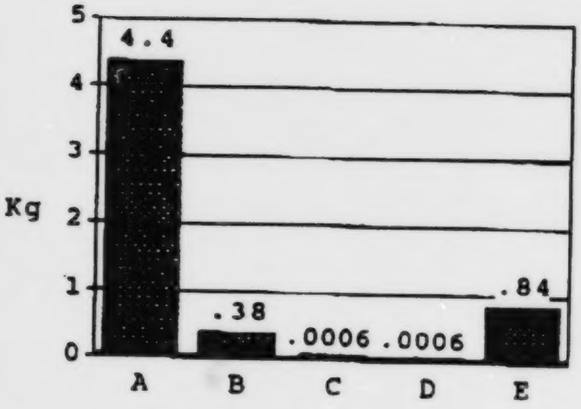
Particulates

Figure 4



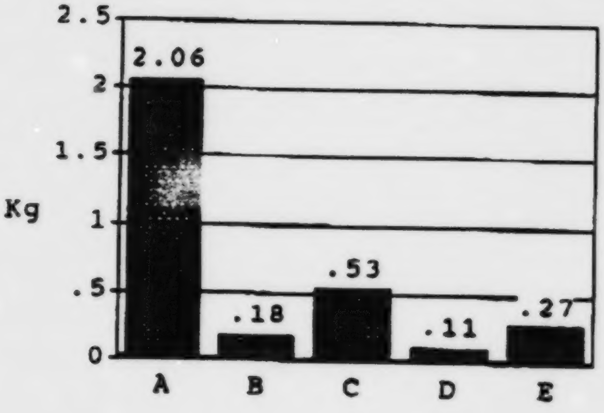
Carbon Monoxide

Figure 5



Sulphur Oxides

Figure 6

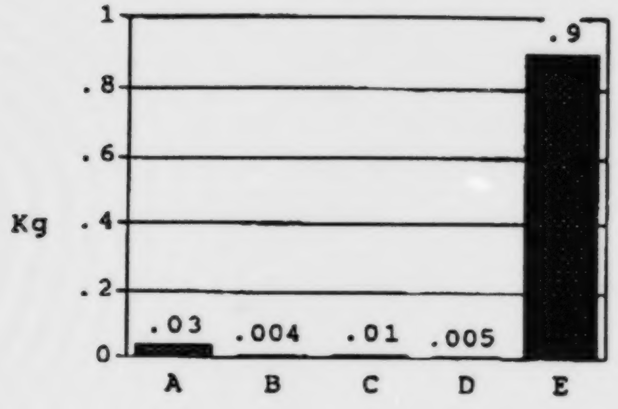


Nitrogen Oxides

Figure 7

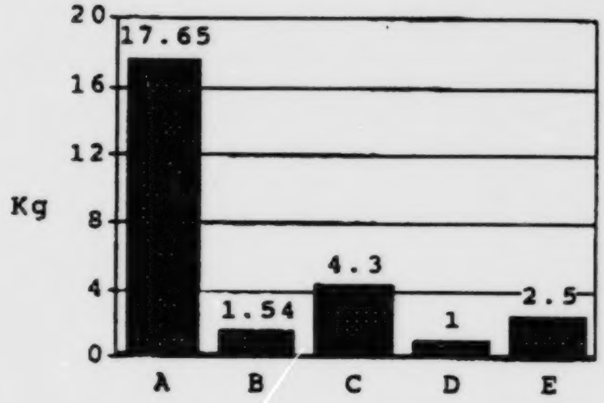
A = Diesel Fired Ground Heater
B = Diesel Fired Boiler
C = Propane Fired Ground Heater
D = Natural Gas Fired Boiler
E = Coal Fire

Emissions Comparison



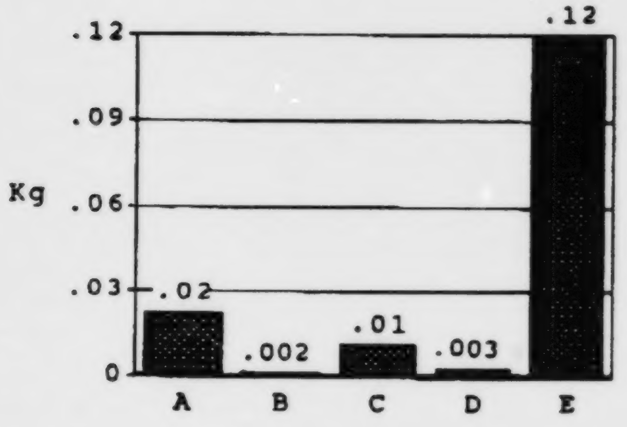
NonMethane Volatile
Organic Compounds

Figure 8



Carbon Dioxide

Figure 9



Methane Volatile
Organic Compounds

Figure 10

A = Diesel Fired Ground Heater
B = Diesel Fired Boiler
C = Propane Fired Ground Heater
D = Natural Gas Fired Boiler
E = Coal Fire

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FIFTH ANNUAL PIPELINE CONFERENCE
SPONSORED BY:
THE CANADIAN PETROLEUM ASSOCIATION

Palliser Hotel
May 14, 15 and 16, 1991
Calgary, Alberta

Topic

QUALITY IMPROVEMENT PROJECT BY PROJECT

by

William Sol
Vice President, Engineering
Partec Lavalin Inc., Calgary

INTRODUCTION

There is one thing that most quality management gurus agree upon; workers can do very little to improve quality on their own. As stated in the words of Dr. W. Edwards Deming (1), "Workers are only responsible for 15% of quality problems, the system is responsible for the other 85%. The system is the responsibility of management."

Today I am going to discuss the critical role that a project team plays in customer satisfaction and continuous improvement.

I believe that almost all quality improvements come about through simplification of designs, procedures and work processes.

Ten years ago I used to stand in front of a client and proudly exclaim that we had 14 volumes of Engineering Manuals that covered standards, procedures, design guides and standard forms.

I now realize that such extensive systems and procedures are prohibitive to maintain and that few people really read or comprehend them.

Most project execution systems and procedures in use today have evolved over the past 10 to 20 years. They have been built on the basis of control, and have grown to prevent the re-occurrence of problems from "special causes" experienced on past projects. Today we must examine our work processes with a view to simplifying them such that they provide the basic norm necessary to prevent "common causes" of problems. The basis of continuous improvement lies in being able to distinguish between "common causes" that are attributed to the system or process, and "special causes" that are related to a specific individual or event.

PRINCIPLES OF TOTAL QUALITY MANAGEMENT

When we start talking about things like "special cause" and "common cause" it is probably a good point to overview Total Quality Management's Basic Principles:

- Quality can and must be managed
- Our processes are the problem, not our people
- Everyone has a customer

Total Quality Management is:

- Quality consciousness
- Continuous change
- Continuous improvement
- Focus on customer (internal/external)
- Concept of teamwork
- Commitment

Total Quality Management is not:

- A program
- Limited to blue collar workforce or white collar workforce
- Limited to manufacturing or high volume processes
- Firefighting
- A quick fix

Continuous Improvement is based on:

- Understanding the process
- Involving the people
- Focusing on the customer

In the analysis of the processes to identify faults and eliminate waste, it is common to presume every defect or mistake is attributable to someone or a special event. The fact is most troubles come from the system. The term "common cause" has been defined to refer to those faults of the system. The term "special cause" or "assignable cause" has been defined to refer to those faults caused by fleeting events or individuals. The most serious mistake a manager can make is to work problem solutions as if they were a special cause, when in fact there is only common cause. Workers get blamed when they have no control and thus become discouraged.

We can all probably think of a case where those doing piping material take-off were blamed for material overruns or underruns even though it was a management decision to buy early and allow continuing design changes.

APPLYING THE CONCEPTS

We can simply think of the system as the framework through which the engineering, procurement and construction is planned, executed and monitored. Our systems are composed of a large number of repeatable activities or work processes that become formalized in the form of standards and procedures.

The integration of work processes through planning and monitoring is a responsibility of the project management team. Nowhere is this integration of processes more important than in the transition from the front-end (definition) phase of the project to the detailed design phase (production). This phase sets the direction for the production phase in which the major portion of manhours is spent. The front-end phase basically consolidates the design so that it can be detailed and finalized during the production phase. The relationship between the P&ID's (process and instrument diagrams) development process and the piping design process of a typical facility is illustrated in Figure 1. Many other facets of a project's development can be thought of in terms of a definition phase and subsequent production phase. Another example would be the establishment of electrical single line drawings which then form the basis for the power system design.

If the design is not finalized and the front-end phase is weak, the production phase will require substantial rework, resulting in low productivity, budget overruns and potential schedule slippage. As you can see from Figure 2, a premature start of the production phase can have a similar effect.

It seems to me that you would want to expend considerable effort in examining the process of "fixing" P&ID's for the production phase. A complete understanding of this process is necessary if you wish to identify the cause of problems or continuously improve performance and quality.

To achieve the desired result requires the bringing together of internal and external customer requirements. For the manager and his project team to satisfy the customer's requirements, these requirements must be negotiated and validated so that there is a clear understanding and agreement up front. This understanding is critical and the critical needs for the project definition stage should be documented in the project plans as firm commitments.

Another quality coach, Philip Crosby, says that "at least half of quality problems are caused by not clearly stating what the requirements are."

In a recent review with Shell of the Caroline project's procurement cycle, an informal review stage of data sheets was replaced by a formal approval that eliminated the potential for recycle at a later more critical point in the process. In addition, it was established that the requisition for purchase, along with all technical documents conforming to the selected vendor would be prepared without first having Shell's approval. This eliminated an unnecessary step and shaved time from the overall cycle. This would have been a good time to measure progress, to identify with the improvements and establish a new performance base from which to measure progress and continuously improve. This was not done and we missed an opportunity to acknowledge our achievements in reducing the procurement cycle time and to establish a basis for continuous improvement. If a process is stable and not experiencing any problems associated with "special cause" it is important to set reasonable goals for improvement.

The integration of engineering with construction is another critical work process interface. Engineering must recognize that its customer is construction. If quality management principles are applied throughout construction, every tradesman would have everything necessary to complete his work without delays. He would have the right material at the right time, with the correct plans and tools to carry out the work safety and would get it right the first time, every time.

To demonstrate what potential quality management principles have in Russian pipeline construction, I would like to show you a few slides of work carried out on the Tenguiz project by Russian trades under their system and management.

It can be extremely difficult to identify the problems, let alone break them up into manageable segments for improvement. The use of flow charts, cause-and-effect diagrams or some of the other helpful charts shown in Figure 3 are frequently referenced in most current books on quality management.

According to William Conway, these simple charting techniques can be used to solve most of a company's problems. A simple flow chart is often enough to identify activities that do not add value or identify the interface areas where most problems occur.

Process definition focuses on the interfaces that exist within a process and between processes. The procedure for defining a process follows: (2)

(1) Define the purpose of the process, specifically focusing on the value added by the process (as related to customers' needs).

(2) Verify ownership of the process.

(3) Identify the primary outputs of the process. Identify the customers who use or receive the process outputs.

Identify the customers' needs and expectations for the outputs and, if necessary, negotiate the needs with the customers.

(4) Translate the customers' needs and expectations into outputs. Determine what characteristics of the output you can measure to assess whether you are meeting customers' needs. Define the criteria for success for the process outputs.

(5) Identify the required inputs. Identify the suppliers who provide the inputs. Determine your requirements for the inputs. Communicate and negotiate your input requirements with suppliers.

The procedure for monitoring a process is as follows: [2]

(1) Review the customer needs and the process requirements. Review the criteria for success for each process activity and the output. Obtain and review feedback from customers, suppliers and users of the process.

(2) Determine and implement internal measures to assess effectiveness and efficiency.

(3) Collect and review data gathered on measures. Monitor and assess process output performance according to requirements.

The procedure for improving a process is as follows: [2]

(1) Review the data and information gathered in the monitoring function. Identify which aspects of the process are working well and maintain them. Identify which aspects of the process are not working well, Identify nonconformances.

(2) Identify areas for improvement. Review and rank order areas for improvement. Consider the staff, budget, schedule and results from each proposed improvement. Identify and verify root causes.

(3) Select areas for improvement. Obtain management approval for selected improvements.

(4) Do the tasks required to achieve the selected improvements.

(5) Validate improvements. Assess process conformance to the requirements. Determine levels of customer satisfaction. Review process periodically to ensure improvement is still in place and effective.

SUMMARY

Too often, people tend to grumble about what they are given, but they seldom try to do anything about it. A formal process of system improvement gives people the courage and backing to insist on better input and involvement.

Total Quality Management principles can really make their mark when they are applied to identify causes of system problems and involve people in improvement of the system.

Project management must champion the quality management process on a project with complete support of senior corporate management. Continuous improvement can only occur as improvements made on a project by project basis are applied corporate-wide to meet the future requirements of internal and external customers.

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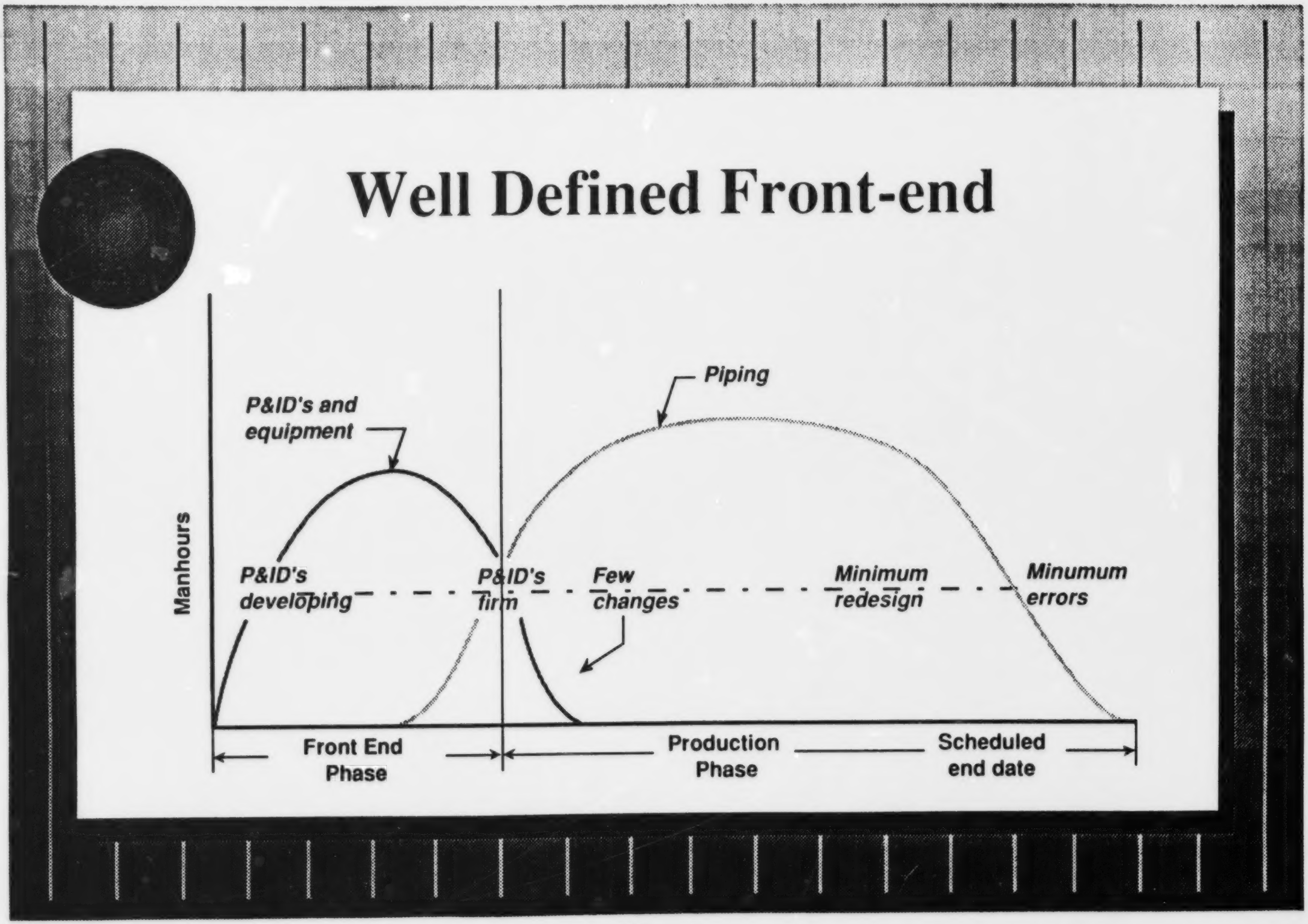


Well Defined Front-end

Figure 1

Poorly Defined Front-end

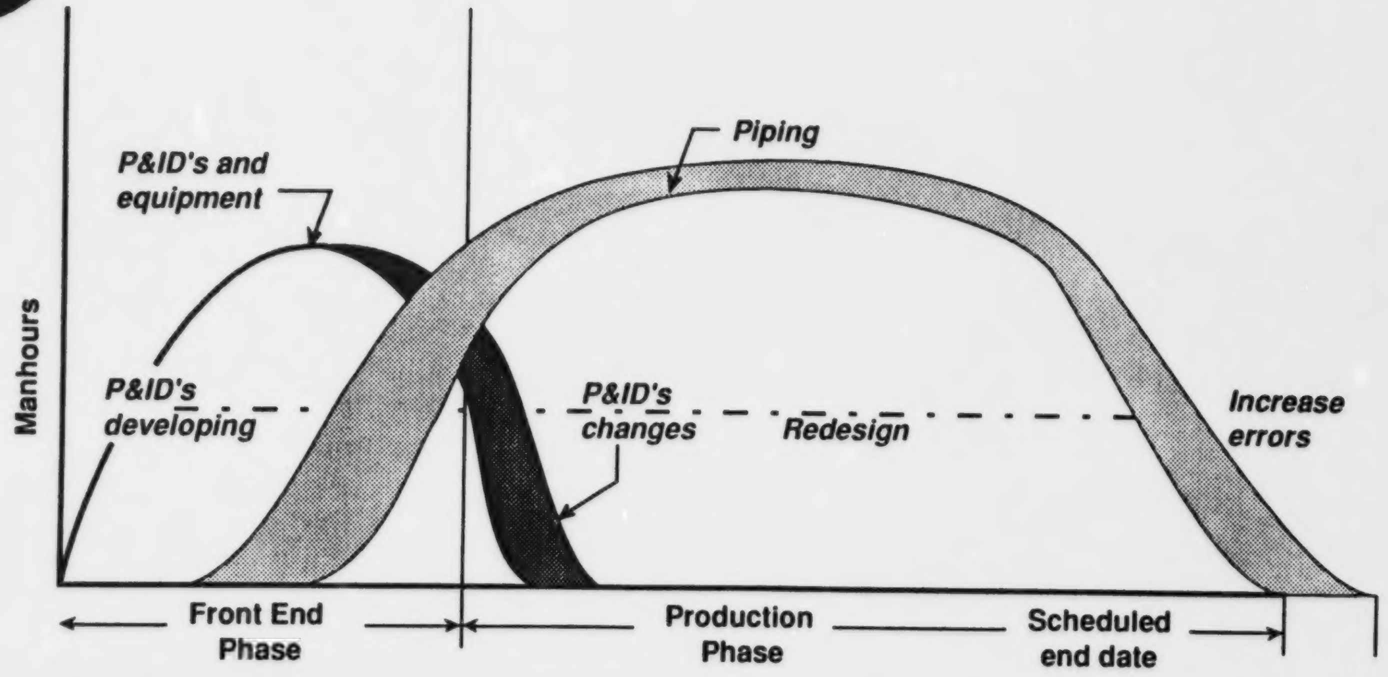
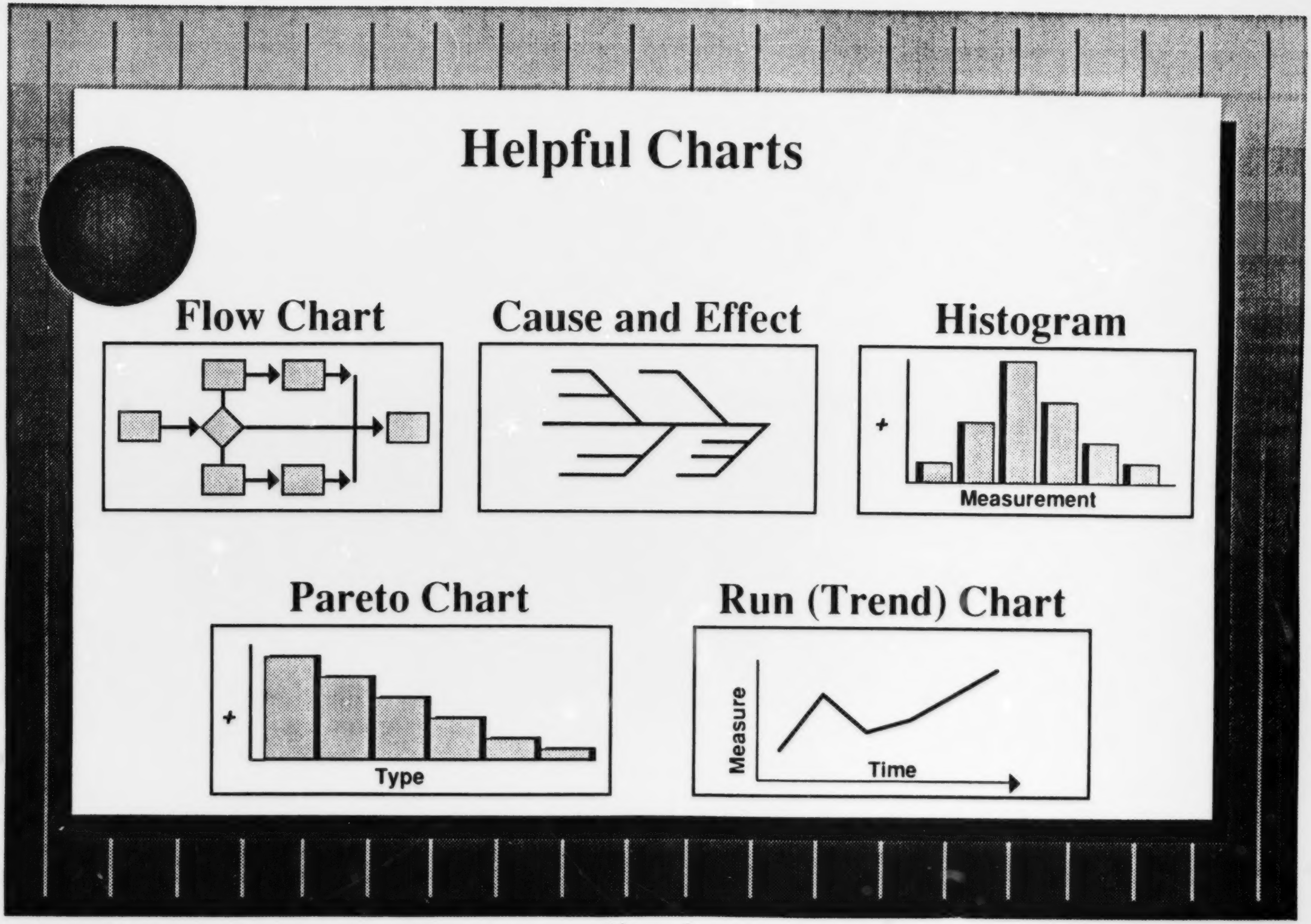


Figure 2



Helpful Charts

Flow Chart

Cause and Effect

Histogram

+
Measurement

Pareto Chart

+
Type

Run (Trend) Chart

Measure
Time

Figure 3

1991 CPA PIPELINE CONFERENCE:
PIPELINES IN A CHANGING ENVIRONMENT
May 14-16, 1991
Palliser Hotel
Calgary, Alberta

A FERC VIEW ON OIL PIPELINE RATEMAKING

PRESENTED BY:

DENNIS H. MELVIN
Deputy Assistant General Counsel
for Gas & Oil Litigation
Federal Energy Regulatory Commission
Washington, D.C.

I. INTRODUCTION

Let me tell you a little bit about myself first so that you know from whence I come and where I get my slant on things. I am the Deputy Assistant General Counsel in the Gas and Oil Litigation section within the Office of General Counsel at the Federal Energy Regulatory Commission. Our section, which is also sometimes referred to as the trial or the litigation Staff, represents the public interest in oil and gas pipeline rate matters that have been set for hearing. The trial Staff, along with our group of technical experts, is a different group of people from those lawyers and technical experts who give advice to, and draft orders for, the Commission. That group is known as the advisory Staff. We are the folks you see in the hearing rooms. They are the ones who, at the direction of the Commission, prepare the final orders and opinions on rate matters.

I have been a trial lawyer specializing in rates at the FPC/FERC for fifteen out of my seventeen years of federal service. For many of those years, I have dealt with oil pipeline rate matters. I was the lead counsel for the FERC trial Staff in the TAPS, Kuparuk, Endicott and Milne Point cases. I currently act as the primary supervisor within the trial Staff for all oil pipeline rate cases.

There are a number of oil pipeline matters that I would like to discuss with you this morning. The first deals with Opinion Nos. 351 and 351-A, which were issued in the ARCO Pipe Line Co.

case on July 18, 1990 and December 18, 1990, respectively. 1/ This case represents the first instance in which the Commission has attempted to interpret its still relatively new trended original cost (TOC) approach to cost based ratemaking. To the extent that the very recent Kuparuk decision amplifies on the TOC methodology, I will also mention that. 2/ Next, I will explore what has come to be known as the Buckeye alternative to cost based ratemaking. My discussion will focus upon Opinion No. 360, which was issued in the Buckeye Pipe Line Company case on December 31, 1990. 3/ Finally, I will try to give you some insight and practical advice regarding FERC procedures that those of you who deal with the Commission may find useful. I should add a footnote at this point. As I speak on these subjects, I wish to emphasize that I am not authorized to, and I do not purport to, speak for the FERC. The views I express are entirely my own.

There are many people, perhaps myself included, who for many years believed that we might never see the FERC issue an opinion in a full litigated oil pipeline rate case. However, I am here today to tell you that has changed. It is my view that our new Chairman, Martin Allday, who has been at the helm now since November 1989, has started moving on the agency's backlog of oil

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1/ 52 FERC ¶ 61,055; 53 FERC ¶ 61,398.

2/ Kuparuk Transportation Co., 55 FERC ¶ 61,122 (1991).

3/ 53 FERC ¶ 61,473.

pipeline cases and will act on future cases in the normal course of business as they arise. In fact, the Commission has acted on three complex oil pipeline cases in the last ten months alone. I think that the Commission realizes that the number of contested oil pipeline filings is growing every year and, absent legislation, they are going to have to be dealt with. More importantly, now that we have a few oil pipeline rate matters decided, it will in turn better enable pipelines to fashion acceptable rates and rate policies, it will better enable shippers to determine whether to protest and intervene in a rate case, and it will make it easier for the FERC Staff to determine whether to recommend suspension of rate filings and to set them for hearing. And even if a case does get set for hearing, we'll all be in a much better posture to negotiate a settlement on an informed basis.

II. THE ARCO DECISION

Opinion Nos. 351 and 351-A represent an important, landmark decision for the Federal Energy Regulatory Commission. Not only is it the first decision in a fully litigated oil pipeline rate case, but it and the recently issued Kuparuk decision and the underlying Opinion Nos. 154-B and 154-C (which generally describe the Commission's oil pipeline TOC ratemaking methodology) [4], constitute the only cost based ratemaking benchmarks we have for the FERC Staff and the oil pipeline industry. These opinions will continue to be the rules we operate under unless and until altered by the Commission or the courts.

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[4] Williams Pipe Line Co., 31 FERC ¶ 61,337 (1985), modified 33 FERC ¶ 61,327 (1985).

It is important that the Commission maintain a clear, workable cost based ratemaking methodology for the oil pipeline industry. Even in this era of two-stage Buckeye type proceedings, there will doubtlessly always be some pipelines, or specific markets for pipelines, that will not be subject to the constraints of competition, and will therefore need cost based ratemaking to assure just and reasonable rates. Until markets are found to be competitive, cost based ratemaking is going to be around for the foreseeable future.

Depending on your point of view, Opinion Nos. 351 and 351-A could be considered either a big win for ARCO, or a big win for the Staff. On the one hand, ARCO will not have to pay any refunds because it won on most of the fact-specific issues. On the other hand, most of the generic policy issues were decided in accordance with the Staff's arguments. I will limit my remarks to those issues of general interest to the industry, i.e. primarily the policy issues.

Opinion Nos. 351 and 351-A confirm the Staff's position on the nine issues noted below. Since Opinion Nos. 351 and 351-A discusses each of these in some detail, I won't mention them here except to simply note them for you.

1) All parties in the ARCO case had agreed that Opinion No. 154-B required ARCO to develop a starting rate base as of January 1, 1984.

However, Opinion No. 351 affirmed the ALJ's ruling that ARCO's parent capital structure as of June 30, 1985 (the date Opinion No. 154-B was issued) should be used to derive the starting rate base, thereby rejecting ARCO's contention that it should use a cumulative average of its parent capital structures from 1970-1983. Kuparuk, being a new pipeline, had no starting rate base issues.

2) The Order affirmed the ALJ's ruling that ARCO is not entitled to adjust its starting rate base to include an AFUDC allowance (or a return during construction) on the equity capital used to construct the assets which make up the starting rate base.

3) The Order affirmed the ALJ's ruling that ARCO is not entitled to capitalize past overhead expenses into the original cost portion of the starting rate base.

4) The Order affirmed the ALJ's ruling that ARCO is not entitled to amortize the write-up in its starting rate base as a cost of service expense.

5) Under the heading of deferred taxes, the Order affirmed the ALJ's ruling that the time value associated with taxes which ARCO has collected from the shippers but not yet paid to the Treasury (*i.e*. deferred taxes), must be reflected as a

deduction from rate base of the full amount of the deferred taxes. ARCO had suggested that this time value could be reflected as a revenue credit to the cost of service equal to a risk-free return on the deferred taxes. A similar argument was made in the Kuparuk case, with similar results.

6) Also under deferred taxes, the Order reversed the ALJ and found that deferred taxes should be deducted from the rate base before rather than after the rate base is trended. The Kuparuk opinion confirmed this result, as well.

7) Finally under deferred taxes, the Order affirmed the ALJ's ruling that ARCO's write down of the value of its oil inventory because of a drop in the price of oil, does not create an out of pocket tax loss or a cost of service expense until such time as the inventory is in fact sold. The Commission did, however, permit ARCO to adjust its working capital allowance upward to restate the value of its written-down inventory at its true cost.

8) The Order reversed the ALJ and found that the after tax return allowance should be calculated by applying a single weighted cost of capital to a combined debt and equity rate base. ARCO had proposed a separate application of equity and debt

rates of return to separate equity and debt rate bases. On rehearing, the Commission agreed that it should recognize the fact that the equity portion of oil pipeline rate bases will continue to grow over time as deferred earnings continue to accrue under the trended original cost (TOC) methodology. As a result, the concept of a single weighted cost of capital was retained, but it will be calculated using an equity capital ratio increased to account for the deferred earnings. This method was also adopted in the Kuparuk case.

9) For rate of return purposes, the Order affirmed the ALJ's ruling that the Commission's preference, as expressed in Opinion No. 154-B, is that when the parent guarantees an oil pipeline's external debt, then that parent's capital structure should be used for rate of return purposes. ARCO had argued for a higher equity percentage. This approach was also adopted in the Kuparuk case.

There were, however, two issues of general application for which the Order did not adopt Staff's arguments:

1) The Order modified the ALJ's finding with regard to the rate of return on equity. Staff had proposed a 12.5 percent return and ARCO a 14.1 percent return. The Staff's proposal was based primarily upon a comparison group of six natural gas pipelines which, in Staff's view, faced risks comparable to the risks faced

by ARCO. However, after correcting for a technical error in Staff's study, and after finding that ARCO was riskier than the Staff's comparison group of natural gas pipelines, the Judge gave ARCO a 13.15 percent nominal return on equity. That was about half-way between the Staff and ARCO proposals.

It would be an overstatement to say that Opinion No. 351 went into a lot of detail in its discussion of equity returns. In fact, all the Order really did was to state that, because the ALJ's upward risk adjustment was "insufficient", and because ARCO's capital structure was "abnormal", the company was entitled to its recommended 14.1 return. It is somewhat difficult, therefore, to draw much in the way of guidance for future rate cases on this score. Not surprisingly, neither ARCO nor AOPL sought rehearing on this issue, and Staff, of course, is not allowed to seek rehearing.

Despite the ultimate finding of Opinion No. 351 on this issue, Staff is of the view that it should continue to evaluate oil pipeline returns by making comparisons with gas pipelines. This technique has been widely accepted at the FERC for years, and it is commonly used in cases where the stock of a pipeline is not publicly traded, as is the case with many oil pipelines. Particularly now that the Commission has placed so much emphasis on changing the gas pipeline industry into a more competitive environment, we think that a good case can still be made for comparing at least some gas pipelines with some oil pipelines.

In fact, the Commission specifically endorsed this view in the Kuparuk case.

Now that doesn't mean we'll necessarily come out with high or low equity returns for oil pipelines. It just means we have to do a better job of finding gas pipelines that are truly comparable in risk to the oil pipeline we are analyzing.

2) As the Staff recommended, Opinion No. 351 did not allow ARCO to adjust its starting rate base to include an AFUDC allowance (a return during construction) on assets which were constructed prior the date as of which ARCO's starting rate base was calculated (January 1, 1984). However, according to Opinion No. 351, ARCO is allowed a return on the capital invested to construct assets (i.e., an AFUDC allowance) after that date. The issue, therefore, concerned what AFUDC rate to allow for 1984 and beyond.

It is usual Commission practice to equate the equity AFUDC rate with the equity rate of return. Therefore, the equity AFUDC rate as of April 1, 1986 (the effective date of ARCO's rates) should be 14.1 percent to be consistent with the equity rate of return found to be reasonable. The Staff had no problem with that. However, ARCO asked for an equity AFUDC return for the interim years (1984-1985) higher than 14.1 percent, to account for what it said was the higher cost of money during those years. Staff argued to maintain the same AFUDC rate for all years.

In its discussion of the merits of this issue, the Commission said that since the rate of return for 1986 was not automatically representative of a reasonable cost of money for 1984 and 1985, the AFUDC rate did not necessarily have to equal the equity rate of return for those years. "In light of the difficulties involved", the Commission allowed ARCO a 17 percent equity AFUDC rate for those years.

In this case, the Staff did not perform a separate study on the cost of money for those intervening years. If the issue were to arise again, I suspect we would.

As for future oil pipeline rate cases that are tried pursuant to the Opinion No. 154-B methodology, I expect the FERC Staff will implement the policies as they are laid out in Opinion Nos. 351 and 351-A, and as I have described them to you.

III. THE BUCKEYE ALTERNATIVE

The method for setting cost based rates is not the only area of controversy now being addressed in oil pipeline rate cases coming before the Federal Energy Regulatory Commission. As most of you know by this time, in 1988 the Commission adopted an alternative to strict cost based ratemaking for oil pipelines. In two orders issue in a Buckeye Pipe Line proceeding 5/, the Commission adopted an alternative to the ratemaking methodology set forth in Opinion Nos. 154-B and 154-C. In the Buckeye orders, the Commission held that clearly identified non-cost factors such as competition and the lack of market power may warrant a departure from the traditional cost based rate review

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5/ Buckeye Pipe Line Co., 44 FERC ¶ 61,066 (1988); Buckeye Pipe Line Co., 45 FERC ¶ 61,046 (1988).

process. Accordingly, the Commission found that it could, if competitive conditions exist, require only what it termed as "generalized cost data" to support Buckeye's rate filings. Thus, the Commission provided Buckeye an opportunity to demonstrate, in the first phase of a bifurcated proceeding, a lack of market power that would warrant "light-handed" regulation. Later, in Texas Eastern Products Pipeline Co., 45 FERC ¶ 61,306 (1988), the Commission held that all oil pipelines have an absolute right to elect to pursue this Buckeye procedure.

There has thus far been only one case, Buckeye, that has gone to trial on market power issues. That case was the subject of a Commission opinion (Opinion No. 360) issued on the last day of 1990. 6/ At this point in time, we have three other oil pipelines that have also opted to phase their rate cases. 7/ The market power (or Phase I) issues in each of these case are currently scheduled to go to hearing in 1991.

In view of this latest trend among oil pipelines to opt for two stage rate cases, I want to spend a few minutes on the subject of competition and market power. I should mention at the outset, however, that I am not an economist. Moreover, if I had to give the lawyers and accountants in this group one overriding piece of advice, it would be not to venture into the quagmire of

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6/ Buckeye Pipe Line Co., 53 FERC ¶ 61,473.

7/ Williams Pipeline Co., Docket No. IS90-21-000; ARCO Pipe Line Co., Docket No. IS90-34-000; Amoco Pipeline Co., Docket No. IS90-30-000.

a market power analysis without the services of a good economist. Given the experience of the Buckeye case, it is apparent that these studies will typically require extensive discovery and as much time to prepare as a cost based rate case. The issues can be complex, and we have little precedent for guidance. So you should not look upon this procedure necessarily as a means of short-cutting the time and expense of a typical cost based rate case. In fact, given the two phase nature of such proceedings, they could turn out to be more expensive and more time consuming than a typical cost based rate case. Of course, the potential for light-handed regulation may be a sufficient incentive to warrant such an investment.

Let me also remind you at this point that the Commission's recent policy of allowing these two stage proceedings, and the possibility of light-handed regulation, has yet to be tested in the courts. Indeed, even the cost based ratemaking methodology of Opinion Nos. 154-B and 154-C has yet to be presented to the courts. I only mention this because there is always the possibility that Commission policies such as these may be rejected, altered or sent back by the appellate courts. It has happened before.

Having said that, let me briefly turn to the more important elements of a market power study. There is no doubt but that we could spend most if not all of an entire conference discussing the fine points of determining market power. I will try to highlight just a few considerations.

The Buckeye Decision

On February 12, 1990, an Administrative Law Judge issued an Initial Decision in the Buckeye case in which he found that Buckeye lacked significant market power in all of its relevant markets. After briefs on and opposing exceptions were filed by the parties, the Commission conducted its own analysis of Buckeye's market power based on the record developed at the hearing, and it issued Opinion No. 360 in December.

In that Opinion, the Commission affirmed the ALJ on the threshold matters of defining the relevant product and geographic markets. Specifically, it:
1) defined the relevant product market as the transportation of refined petroleum products, and 2) defined the relevant geographic markets served by Buckeye to be at least as large as the Department of Commerce, Bureau of Economic Analysis Economic Areas (BEAs). Although that's quite a tongueful, BEAs are essentially geographic regions surrounding major cities that are intended to represent areas of actual economic activity. The Commission then evaluated whether Buckeye had significant market power in each relevant geographic market.

As a sidebar, I should mention that there was also a threshold definitional problem of what do we mean when we say "significant market power"?

The Judge in the Buckeye case defined significant market power as an ability to increase prices by 15 percent for a substantial period without losing sales. Therefore, in the case of a pipeline shipping jet fuel for a shipper who sells to an airline, if the pipeline could raise its rates by 15 percent and still transport just as much fuel for the shipper, that would have indicated market power to this Judge. In the view of trial Staff's economists, however, the proper test was much more stringent. We said that significant market power does not exist unless the pipeline can raise prices to the point where the airline will actually begin to use less fuel, thereby having less flights and causing an economic loss to society, i.e when the output of flights is measurably reduced. Staff's definition, therefore, would not have found significant market power unless Buckeye was able to raise its prices so high that the airline would actually start to buy less fuel. The Commission, however, did not accept Staff's definition of significant market power and it adopted the ALJ's definition.

As its first step in determining whether significant market power existed in the relevant BEA's, the Commission screened for market concentration in each market by using the Herfindahl-Hirshman Index (HHI), which is an index often used by the Department of Justice for measuring a firm's share of the market. In this case, measurements were based upon actual deliveries into the market. In other cases other measures, such as delivery capability, may be a more appropriate measure.

If Buckeye had a particularly low HHI in a given market, thereby indicating a low market share for Buckeye in that market, the investigation ended there and Buckeye was presumed to lack significant market power in that BEA. If the HHI was not low, the Commission considered and weighed various other factors such as the potential entry of competitors into the market, available transportation alternatives, market share, availability of excess capacity, and the presence of large buyers able to exert downward monopsonistic pressure on the transportation rates. After completing this analysis for each market the Commission then reached a conclusion as to whether, on balance, these factors established that Buckeye has significant market power in that market such as to necessitate continued close regulatory oversight of its rates in that market.

Of the 22 relevant markets considered, the Commission affirmed the ALJ's finding that Buckeye lacks significant market power in 15 markets, it made no findings with respect to two markets since Buckeye had no tariff on file for those markets and does not service them, it found that one market should continue to be regulated because the record was insufficient to make a finding of Buckeye's market power in that market and, finally, the Commission found that in the remaining four markets Buckeye had significant market power.

Let me just briefly divert for a moment to discuss two major factors affecting the market power analysis which we believe were important in this case and are worthy of even further consideration in future market power cases.

Interdependent Pricing

One of these factors is the concept of interdependent pricing. We believe (and the Commission agreed in Opinion No. 360) that the Commission must evaluate not only whether the oil pipeline under investigation can exercise significant market power solely by itself, but also whether it can do so in concert with other large sellers of transportation services in its markets. If the Commission were to focus only on whether the pipeline acting alone lacked significant market power in a given market, it could miss the very real possibility that significant market power may be exercised by the pipeline and other large sellers pricing interdependently.

Such a situation can arise when there are a relatively small number of sellers (in this case, transportation sellers) and when barriers to entry make it difficult for others to enter into the transportation market on a large scale. In other words, a relatively few transportation suppliers control most of the market. In these circumstances, the distinct possibility exists that an oil pipeline and the other transporters will not act independently, but that they may in effect cooperate with each other by allowing one transporter to lead the others, or by simply taking the likely response of their competitors into account when prices are set.

Let me emphasize at this point that I'm not talking about collusion, which is prohibited by the antitrust laws. What I'm talking about is what the courts have referred to as conscious parallelism, or interdependent pricing, which is not a violation of Section 1 of the Sherman Act. However, interdependent pricing, although legal, can have a distinct impact on the ability of competition to keep prices at a just and reasonable level.

I might note that the Commission in 1989 specifically held in a gas pipeline case that consideration of "interdependent behavior" is necessary to evaluate the extent of market power. 8/

Potential Entrants

Another major factor that Staff believes is important to any analysis of market power is an evaluation of potential entrants to a market, i.e. those who could step in and compete for business should a pipeline's price for transportation get too high. Indeed, the Judge in Buckeye suggested that the number and type of transportation alternatives available to buyers of petroleum transportation services was "the most important factor." We did not disagree with the Judge on that score. Viable alternatives help to keep prices down, and the existence of these alternatives would tend to indicate that the pipeline does not have significant market power. However, it is not sufficient to merely identify and list all those potential transporters who might serve a given market, as the Judge did. Staff believes (and the Commission appears to agree) that a

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8/ El Paso Natural gas Co., 49 FERC ¶ 61,262 at 61,909 and 61,918-19 (1989).

showing must be made that the transportation alternatives identified are in fact true alternatives to the pipeline.

What is a true alternative? Generally speaking, a true alternative is one that could 1) easily and in a timely fashion, 2) step in and profitably serve the market at a price equal to or less than the highest existing price, and 3) deliver volumes equal to those which are being displaced by the oil pipeline.

Only if an entity meets these tests could it really be considered as a viable constraint on the oil pipeline's ability to exert market power. The concept is somewhat similar to one on the gas side which states that unless the terms of a given service are substantially comparable to those being offered by the pipeline, it cannot be considered a true, competitive alternative to the pipeline. Add to that the requirement here that a service must also be comparable in terms of price to be a true economic alternative, and we have a fairly strict test. In our view, a mere listing of the number and type of potential alternatives does not prove anything.

Once the Commission made the finding that Buckeye did have market power in some of its markets, the question then became how to regulate rates in the competitive versus the non-competitive markets. The Commission originally envisioned this as the question to be answered in Phase II of the proceeding. However, Buckeye had already proposed an experimental program for dealing with these issues. The proposal basically advocated using price changes in markets where Buckeye lacks significant market power to set caps for price changes in the markets where it does have market power. As an added safeguard, the proposal provided that rate increases in markets where Buckeye did not have market power would be a) limited to a 15 percent real increase over any two-year period, and b) limited to the change in the GNP deflator plus two percent.

The Commission accepted this plan, although it changed a number of details in it, and remanded the case back to the ALJ to determine the proper base rates to which the rate cap would apply. The Commission will implement this plan on the Buckeye system on a three-year trial basis. At the end of each of the three years, Buckeye will submit annual reports detailing price and revenue changes under each tariff. The Commission did not say what it would do with Buckeye's rates at the end of the experiment.

At this point I want to highlight a matter which arose in Opinion No. 360, and which is of special importance to shippers who may be contemplating intervening in an oil pipeline rate case such as this. You will recall that I noted that after Opinion No. 360 found that Buckeye had market power in five of its markets, it remanded the case back to the ALJ to set the proper base or starting rates for those markets. However, it is important to note that, as the result of a later amendment to the language of Opinion No. 360, the remand really only applies to those markets in which the Air Transport Association (ATA), the sole intervenor in the case, operates. This means that even if Buckeye was found to have market power in a given market, it will nevertheless be treated as if it did not have market power unless there is a shipper or other intervenor (in this case, ATA) protesting the rates in that market. In short, if you are concerned about the prospects of light-handed regulation in the markets you serve, you must intervene in a rate case and protest the proposed rates.

IV. **MAKING A FILING AT FERC**

For those of you who operate oil pipelines in the United States, if what I've said hasn't discouraged you so far from ever making a filing at the Federal Energy Regulatory Commission, I thought the least I could do is to give you some information that will perhaps make the filing process less painful for you and, as an equally laudable goal, an easier experience for the FERC Staff. Since rate filings seem to generate the most interest, both inside and outside of the agency, I will concentrate for the most part on that process. In that regard, the most often asked question is: What information do I have to submit so that the FERC Staff can make a determination whether to suspend, or better yet not to suspend, a rate filing?

Bearing in mind that the FERC regulations do not require an oil pipeline to submit any supporting documentation with a rate filing, some pipelines opt to do just that -- file nothing but the tariff change notice. However, that gives the agency nothing upon which to make a finding of reasonableness, and may well lead to a suspension and formal discovery procedures. It would seem to me much simpler for a pipeline to submit the necessary information up front with the filing. In fact, let me note at this point that the information gathering process does not necessarily have to await the formal rate filing. The FERC Staff is receptive to, and indeed encourages pipelines to consider, informal pre-filing conferences to discuss in advance what specific information the Staff will need to evaluate the tariff, and to see if we can foresee any obvious problems with it. Many problems are ironed out at this stage, long before the pipeline commits itself to a formal filing.

This also has the advantage of allowing the Staff a somewhat longer time period to make a more reasoned evaluation of the proposal. By FERC regulation, rate filings typically require Commission action within thirty days. 9/ Although this may seem like a long time, it really isn't when you consider that a filing has to be routed to the Oil and Gas Filings Branch, assigned to a reviewer, analyzed for legal and factual sufficiency, protests and interventions evaluated, recommendations prepared and reviewed, placed on the Oil Pipeline Board/Commission agenda, acted upon by the OPB/Commission and an order issued all within that time. It is to no one's advantage

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9/ 18 C.F.R. §§ 341.14 (a), 341.57. By the way, a great deal of confusion appears to exist over how to count days for purposes of the 10 day and 30 day notice periods required by the regulations. The guiding principle is that you do not count the day the filing is made, nor do you count the day the filing becomes effective.

for the Staff to have insufficient time or information to prepare a full evaluation of a filing. Submitting information in advance of or at least concurrently with a filing has proven to be very helpful for all parties involved.

I should note at this point that any information you provide to the Staff, whether before, at the time of, or after a filing is made, is considered to be publicly available. This is necessary in order to avoid any appearance that the Staff is exhibiting an undue bias for any party. If it is necessary for you to divulge what you believe may be confidential information, that is an even better reason to get in touch with the Staff in advance so that these matters can be worked out.

When a pipeline submits information with or in advance of a rate filing, you should know that it is not Staff's purpose during those initial reviews to get all the details and make every possible adjustment in order to derive the exact rates we would advocate if the case were to be litigated. The intent is simply to insert your basic cost of service and rate base information into a formula that conforms with Opinion No. 154-B (as interpreted by Opinion No. 351), and see what level of earnings/rate of return your proposed rate produces. We then compare your earnings prior to the rate increase with what you will earn after the increase. This review is generally done on a system-wide basis rather than on a point to point basis, unless the pipeline opts, as some do, to present the supporting information on a point to point basis. However, if done on a point to point basis, allocations of rate base and costs to specific tariffs must be clearly indicated and supported.

As for what happens then, the specific rate of return, or zone of returns, that will be deemed acceptable will be different for each pipeline, depending upon its individual circumstances. That does not mean that the Staff expects, or even wants at this point in time, a return study justifying your expected rate of return. If, however, you know that your expected rate of return will be noticeably higher than your former return, and there are what you consider to be extenuating circumstances, let us know what they are.

In any event, I cannot give you any guarantees that even if you provide all the information we request, your filing will not be suspended. There really are no hard and fast rules to avoid a suspension. This is particularly true if someone protests and intervenes. Protested rates will normally be suspended. Although one day suspensions are normally the rule, the Commission has instituted the full seven month suspension when in its opinion: 1) the proposed rate increase may have significant anticompetitive effects or impose undue hardships on a shipper, and 2) the maximum suspension is likely to mitigate these effects or hardships. 10/

10/ ARCO Pipeline Company, Docket Nos. IS91-26-000, et. al., order issued April 30, 1991; Cheyenne Pipeline Company, 19 FERC ¶ 61,077 (1982).

What kind of information does the Staff need with a tariff filing? Rather than try to get into the kind of minutia that I suspect you don't want to hear and that I am not well versed on, I have included as an attachment an example of a submission that was made by a pipeline not too long ago to support a tariff filing it made. Although Staff does not necessarily endorse all the pipeline's interpretations of Opinion No. 154-B reflected therein, it does contain the basic information Staff needs to do a 154-B evaluation of its own. For instance, you will find: 1) a summary showing the real equity rates of return with and without the increase, 2) the transition rate base as well as the rate base for each succeeding year up to the year of the filing 11/, 3) the debt/equity ratio used to calculate the transition rate base, 4) the latest actual capital structure, 5) the embedded cost of debt and debt expense, 6) a computation of federal and state income taxes 12/, 7) the inflation adjustment assumptions, 8) any changes in carrier property by year that occurred after 1983 (i.e. additions, retirements, sales, other) 9) a calculation of deferred returns after 1983, 10) an identification of any changes in accrued depreciation by year after 1983, 11) a listing of working capital item balances

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11/ The Staff would like to see the rate base updated as close as possible to the date the rates are proposed to become effective. Therefore, if the rates are to become effective in September and you file in August, Staff would like to have actual information through June if possible.

12/ Be sure to include the applicable state tax rates.

by year after 1983, 13/ and 12) a listing of operation, maintenance and general expenses.

For this last category, the Staff prefers to have at least the last two calendar years of actual information, by month, plus any months in the current calendar year for which actual data is available. This allows us to look for trends and abnormalities within any given expense. To the extent you wish to include estimates and/or projections in your justification, please separately state them and explain them. Depreciation should be based upon the depreciable plant balance for the latest month available. With regard to volume information, the Staff would also like the latest two years of actual throughput, by month, for each tariff if available. If you make projections, explain them.

There you have it. Although interpretations of Opinion No. 154-B may vary, as long as the information described above is made available, the Staff can give your filing the reasoned consideration it deserves. Suffice it to say that the more justification you have for your proposed cost of service, and the more in line it is with Opinion Nos. 154-B and C, as interpreted by Opinion Nos. 351 and 351-A, the better will be its chances for survival.

If you have any questions as to filing procedures, pre-filing conferences or specific details on how Staff develops its

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13/ The working capital balance should be updated to the latest available month, as is the rest of rate base. See, fn. 10.

154-B studies, you may contact the Oil & Gas Filings Branch at (202) 208-0947.

Dennis H. Melvin
Deputy Assistant General Counsel
(202) 208-0042

ATTACHMENT A

SAMPLE OF SCHEDULES NECESSARY TO SUPPORT AN OIL PIPELINE TARIFF FILING

Schedule 1(A)

1989 FERC TARIFF FILING
SUPPORTING DATA

30-Aug-89

ACHIEVED REAL EQUITY RATES OF RETURN

		TEST YR. Without Increase	TEST YR. @ Planned Incr.
Revenue	Schedule 2	64,965	67,480
Expenses			
Operations	Schedule 1 (M) Pg 1	12,325	12,325
Maintenance	Schedule 1 (M) Pg 1	12,436	12,436
General Expense	Schedule 1 (M) Pg 2	17,899	17,899
Pipeline Taxes	Schedule 1 (M) Pg 2	3,187	3,187
Book Depr.	Schedule 1 (M) Pg 2	3,421	3,421
Afudc Depr Pre 84	Sch 1 (B) Pg 8	298	298
Afudc Depr Post 83	Sch 1 (B) Pg 8	55	55
Amort. of Deferred Return	Sch 1 (B) Pg 8	1,266	1,266
Total Expense		50,887	50,887
Net Income Before Intetest and Taxes		14,078	16,593
Interest Expense	Schedule 1 (E)	1,394	1,394
Taxes (St. & Fed)	Schedule 1 (F)	5,335	6,273
NIAT		7,348	8,925
Equity Rate Base End.	Schedule 1 (B) Pg. 8	135,792	135,792
Achieved Return on Equity Rate Base		5.4%	6.6%

Test year based on Fiscal yr. ending 6-30-89, and annualized tariff increases.

Schedule 1(B)
(Pg 1 of 8)

1989 FERC TARIFF FILING
SUPPORTING DATA

TOTAL SYSTEM
TRANSITION RATE BASE COMPUTATION

RATE BASE PROPERTY:

		($M)	
Original Cost of Carrier Property In Service @ 12-31-83	Sch 1(H) pg 1 (Note 1)	127,072	
Less: Land	Sch 1(H) pg 1	521	
Rignts-of-Way	Sch 1(H) pg 1	3,458	

Subtotal - Original Cost-Excluding Land & Right of Way		123,093	100.00%
Carrier Property Accumulated Depreciation @ 12-31-83	Sch 1(J) pg 1 (Note 1)	76,701	
Less: Rignts-of-Way	Sch 1(J) pg 1	2,109	

Subtotal - Accumulated Depreciation		74,592	60.60%
Net Book Value of Carrier Property		48,501	39.40%
		========	
Cost of Reproduction New @ 12-31-83		378,566	100.00%
Less: Accumulated Depreciation		229,411	60.60%

Net Depreciated Cost of Reproduction New		149,155	39.40%
		========	

COMPUTATION of RATE BASE ADJUSTMENTS:

	($M)
Original Cost of Allowance for Funds Used During Const. (AFUDC) @ 12-31-83	7,510
Less: Accumulated Depreciation	1,663

Net Book Value of AFUDC	5,847
	========
Original Cost of Carrier Rights-of-Way @ 12-31-83	3,458
Less: Accumulated Depreciation	2,109

Net Book Value of Rights-of-Way	1,349
	========

SUMMARY of RATE BASE ADJUSTMENTS:

		($M)
Land		521
Net Book Value of AFUDC		5,847
Net Book Value of Rights-of-Way		1,349
Working Capital (End Bal.)	Sch 1(K) pg 1	626
Less: Acc. Deferred Income Taxes		7,346

Total Rate Base Adjustments		997
		========

Note 1 Excludes $482M properties and $61M reserve for trans. to non-carrier in 1988

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1989 FERC TARIFF FILING
SUPPORTING DATA

TRANSITION RATE BASE COMPUTATION

(YEAR 1983)

		($M)		
PROPERTY SECTION:		DEBT 27.1%	EQUITY 72.9%	TOTAL
NBV of Property @ December 31, 1983	Sch 1(B) pg 1	13,144	35,357	48,501
NBV of Land @ December 31, 1983	Sch 1(B) pg 1	141	380	521
NBV of AFUDC @ December 31, 1983	Sch 1(B) pg 1	1,585	4,262	5,847
NBV of R-O-W @ December 31, 1983	Sch 1(B) pg 1	366	983	1,349
Working Capital	Sch 1(B) pg 1	170	456	626
NBV of Property @ December 31, 1983		15,405	41,439	56,844
DEFERRED RETURN SECTION:				
Net Depreciated CRN @ 12-31, 1983	Sch 1(B) pg 1		149,155	
Less: NBV of Property @ 12-31-83	Sch 1(B) pg 1		48,501	
Total Deferred Return @ 12-31-83			100,654	
Times Equity Capital Percentage (1)	Sch 1 C		72.9%	
Deferred Return @ December 31, 1983			73,377	73,377
COMBINED RATE BASE:				
Ending Balance of Property		15,405	41,439	56,844
Ending Balance of Deferred Return		0	73,377	73,377
Rate Base Subject to Trending		15,405	114,816	130,221
Less: Deferred Taxes @ 12-31-83		1,991	5,355	7,346
Rate Base @ December 31, 1983		13,414	109,461	122,875

NOTE (1): Only the equity portion of the rate base is trended for inflation, therefore the total deferred return at December 31, 1983, must be mutiplied by the equity capital percentage to derive the equity portion of the deferred return.

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1989 FERC TARIFF FILING
SUPPORTING DATA

RATE BASE COMPUTATION

(YEAR 1984)

		($M)		
		DEBT 27.1%	EQUITY 72.9%	TOTAL
PROPERTY SECTION:				
Starting Property @ January 1, 1984		15,405	41,439	56,844
Depreciable Ppty. Additions (Sch 1(H) pg 1)		514	1,382	1,896
Other Changes to Depr.Ppty. (Sch 1(H) pg 1)		300	808	1,108
Non-Deprec. Ppty. Additions (Sch 1(H) pg 1)		4	10	14
Other Changes to Non-Depr.Ppty. (Sch 1(H) pg 1)		1	4	5
Working Capital Changes (Sch 1(K) pg 1)		15	39	54
AFUDC Additions		77	206	283
Depreciation Exp. (Sch 1(J) pg 1)		(1,186)	(3,189)	(4,375)
Other Changes to Reserve (Sch 1(J) pg 1)		94	254	348
AFUDC Dep.-Pre 84		(66)	(177)	(243)
AFUDC Depr.-Post 83		0	0	0
NBV of Property @ December 31, 1984		15,158	40,776	55,934
DEFERRED RETURN SECTION:				
Deferred Return @ January 1, 1984			73,377	73,377
1984 Addition	Sch 1(I) pg 1		4,363	4,363
Deferred Return Availble			77,740	77,740
Less: 1984 Amortization Pre 84			0	0
Less: 1984 Amortization Post 83	Sch 1(I) pg 1		181	181
Deferred Return @ December 31, 1984		0	77,559	77,559
COMBINED RATE BASE:				
Ending Balance of Property		15,158	40,776	55,934
Ending Balance of Deferred Return		0	77,559	77,559
Rate Base Subject to Trending		15,158	118,335	133,493
Less: Deferred Taxes @ 12-31-84		2,347	6,315	8,662
Rate Base @ December 31, 1984		12,810	112,021	124,831

1989 FERC TARIFF FILING
SUPPORTING DATA

RATE BASE COMPUTATION

(YEAR 1985)

	DEBT 25.1%	EQUITY 74.9%	TOTAL
	($M)		
PROPERTY SECTION:			
Starting Property @ January 1, 1985	15,158	40,776	55,934
Depreciable Ppty. Additions (Sch 1(H) pg 2)	1,130	3,371	4,501
Other Changes to Depr.Ppty. (Sch 1(H) pg 2)	(3,985)	(11,892)	(15,877)
Non-Deprec. Ppty. Additions (Sch 1(H) pg 2)	0	0	0
Other Changes to Non-Depr.Ppty. (Sch 1(H) pg 2)	(6)	(16)	(22)
Working Capital Changes (Sch 1(K) pg 1)	(100)	(299)	(399)
AFUDC Additions	55	163	218
Depreciation Exp. (Sch 1(J) pg 2)	(1,115)	(2,999)	(4,114)
Other Changes to Reserve (Sch 1(J) pg 2)	2,802	7,537	10,339
AFUDC Dep.-Pre 84	(64)	(190)	(253)
AFUDC Depr.-Post 83	(3)	(9)	(12)
NBV of Property @ December 31, 1985	13,872	36,442	50,315
DEFERRED RETURN SECTION:			
Deferred Return @ January 1, 1985		77,559	77,559
1985 Addition — Sch 1(I) pg 1		4,733	4,733
Deferred Return Availble		82,292	82,292
Less: 1985 Amortization Pre 84		0	0
Less: 1985 Amortization Post 83 — Sch 1(I) pg 1		386	386
Deferred Return @ December 31, 1985	0	81,906	81,906
COMBINED RATE BASE:			
Ending Balance of Property	13,872	36,442	50,315
Ending Balance of Deferred Return	0	81,906	81,906
Rate Base Subject to Trending	13,872	118,348	132,221
Less: Deferred Taxes @ 12-31-85	2,449	6,619	9,068
Rate Base @ December 31, 1985	11,423	111,730	123,153

1989 FERC TARIFF FILING
SUPPORTING DATA

RATE BASE COMPUTATION

(YEAR 1986)

		<------------ DEBT 22.7%	---($M)--- EQUITY 77.3%	----------> TOTAL
PROPERTY SECTION:				
Starting Property @ January 1, 1986		13,872	36,442	50,315
Depreciable Ppty. Additions (Sch 1(H) pg 3) Note		2,958	10,074	13,032
Other Changes to Depr.Ppty. (Sch 1(H) pg 3)		(135)	(458)	(593)
Non-Deprec. Ppty. Additions (Sch 1(H) pg 3) Note		30	102	132
Other Changes to Non-Depr.Ppty. (Sch 1(H) pg 3)		(5)	(18)	(23)
Working Capital Changes (Sch 1(K) pg 1)		49	165	214
AFUDC Additions		42	142	184
Depreciation Exp. (Sch 1(J) pg 3)		(953)	(2,504)	(3,457)
Other Changes to Reserve (Sch 1(J) pg 3) Note 3		(133)	(348)	(481)
AFUDC Dep.-Pre 84		(60)	(204)	(264)
AFUDC Depr.-Post 83		(5)	(16)	(21)
NBV of Property @ December 31, 1986		15,660	43,377	59,037
DEFERRED RETURN SECTION:				
Deferred Return @ January 1, 1986			81,906	81,906
1986 Addition	Sch 1(I) pg 1		4,497	4,497
Deferred Return Availble			86,403	86,403
Less: 1986 Amortization Pre 84			0	0
Less: 1986 Amortization Post 83	Sch 1(I) pg 1		589	589
Acq.of Prop. Sch. 1(b) Pg. 10			677	677
Deferred Return @ December 31, 1986			86,491	86,491
COMBINED RATE BASE:				
Ending Balance of Property		15,660	43,377	59,037
Ending Balance of Deferred Return		0	86,491	86,491
Rate Base Subject to Trending		15,660	129,868	145,528
Less: Deferred Taxes @ 12-31-86		2,461	6,658	9,119
Rate Base @ December 31, 1986		13,199	123,210	136,409

Note 1 Includes $1428M recorded value greater than purchase on Properties.
Note 2 Includes $4M recorded value greater than purchase on Properties.
Note 3 Includes $1024M recorded value greater than purchase on Properties.

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1989 FERC TARIFF FILING
SUPPORTING DATA

RATE BASE COMPUTATION

(YEAR 1987)

		<------------- DEBT 27.0%	-($M)------------ EQUITY 73.0%	-----------> TOTAL
PROPERTY SECTION:				
Starting Property @ January 1, 1987		15,660	43,377	59,037
Depreciable Ppty. Additions (Sch 1(H) pg 4)		3,525	9,531	13,056
Other Changes to Depr.Ppty. (Sch 1(H) pg 4)		(77)	(208)	(285)
Non-Deprec. Ppty. Additions (Sch 1(H) pg 4)		34	91	125
Other Changes to Non-Depr.Ppty. (Sch 1(H) pg 4)		0	(1)	(1)
Working Capital Changes (Sch 1(K) pg 1)		23	61	84
AFUDC Additions		60	163	223
Depreciation Exp (Sch 1(J) pg 4)		(993)	(2,751)	(3,744)
Other Changes to Reserve (Sch 1(J) pg 4)		74	205	279
AFUDC Dep.-Pre 84		(75)	(202)	(277)
AFUDC Depr.-Post 83		(8)	(21)	(29)
NBV of Property @ December 31, 1987		18,223	50,244	68,467
DEFERRED RETURN SECTION:				
Deferred Return @ January 1, 1987			86,491	86,491
1987 Addition	Sch 1(I) pg 1		1,429	1,429
Deferred Return Availble			87,920	87,920
Less: 1987 Amortization			0	0
Less: 1987 Amortization	Sch 1(I) pg 1		666	666
Deferred Return @ December 31, 1987			87,254	87,254
COMBINED RATE BASE:				
Ending Balance of Property		18,223	50,244	68,467
Ending Balance of Deferred Return		0	87,254	87,254
Rate Base Subject to Trending		18,223	137,498	155,721
Less: Deferred Taxes @ 12-31-87		3,689	9,979	13,669
Rate Base @ December 31, 1987		14,534	127,519	142,053

1989 FERC TARIFF FILING
SUPPORTING DATA

RATE BASE COMPUTATION

(YEAR 1988)

		<-------- ($M)	--------	------>
PROPERTY SECTION:		DEBT 31.0%	EQUITY 69.0%	TOTAL
Starting Property @ January 1, 1988		18,223	50,244	68,467
Depreciable Ppty. Additions (Sch 1(H) pg 5)		1,738	3,868	5,606
Other Changes to Depr.Ppty. (Sch 1(H) pg 5) Note		(164)	(365)	(529)
Non-Deprec. Ppty. Additions (Sch 1(H) pg 5)		2	4	6
Other Changes to Non-Depr.Ppty. (Sch 1(H) pg 5)		0	0	0
Working Capital Changes (Sch 1(K) pg 1)		16	35	51
AFUDC Additions		90	200	290
Depreciation Exp. (Sch 1(J) pg 5)		(885)	(2,439)	(3,324)
Other Changes to Reserve (Sch 1(J) pg 5) Note 1		174	480	654
AFUDC Dep.-Pre 84		(90)	(201)	(291)
AFUDC Depr.-Post 83		(12)	(28)	(40)
NBV of Property @ December 31, 1988		19,091	51,799	70,890
DEFERRED RETURN SECTION:				
Deferred Return @ January 1, 1988			87,254	87,254
1988 Addition	Sch 1(I) pg 1		6,050	6,050
Deferred Return Availble			93,304	93,304
Less: 1988 Amortization Pre 84			0	0
Less: 1988 Amortization Post 83	Sch 1(I) pg 1		967	967
Deferred Return @ December 31, 1988			92,337	92,337
COMBINED RATE BASE:				
Ending Balance of Property		19,091	51,799	70,890
Ending Balance of Deferred Return		0	92,337	92,337
Rate Base Subject to Trending		19,091	144,136	163,227
Less: Deferred Taxes @ 12-31-88		4,167	11,043	15,210
Rate Base @ December 31, 1988		14,924	133,093	148,016

Note 1 Excludes $482M properties and $139M reserve for trans. to non-carrier in 1988.

Schedule 1(B)
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1989 FERC TARIFF FILING
SUPPORTING DATA

RATE BASE COMPUTATION

(YEAR 1989)

		<-------------	-($M)-	----------->
		DEBT 31.0%	EQUITY 69.0%	TOTAL
PROPERTY SECTION:				
Starting Property @ January 1, 1989		19,091	51,799	70,890
Depreciable Ppty. Additions (Sch 1(H) pg 6)		7	14	21
Other Changes to Depr.Ppty. (Sch 1(H) pg 6)		(28)	(62)	(90)
Non-Deprec. Ppty. Additions (Sch 1(H) pg 6)		0	0	0
Other Changes to Non-Depr.Ppty. (Sch 1(H) pg 6)		0	0	0
Working Capital Changes (Sch 1(K) pg 1)		0	0	0
AFUDC Additions		176	392	568
Depreciation Exp. (Sch 1(J) pg 6)		(449)	(1,217)	(1,666)
Other Changes to Reserve (Sch 1(J) pg 6)		40	109	149
AFUDC Dep.-Pre 84		(92)	(206)	(298)
AFUDC Depr.-Post 83		(17)	(37)	(54)
NBV of Property @ December 31, 1989		18,728	50,792	69,520
DEFERRED RETURN SECTION:				
Deferred Return @ January 1, 1989			92,337	92,337
1989 Addition	Sch 1(I) pg 1		6,342	6,342
Deferred Return Available			98,679	98,679
Less: 1989 Amortization Pre 84			0	0
Less: 1989 Amortization Post 83	Sch 1(I) pg 1		1,266	1,266
Deferred Return @ December 31, 1989			97,413	97,413
COMBINED RATE BASE:				
Ending Balance of Property		18,728	50,792	69,520
Ending Balance of Deferred Return		0	97,413	97,413
Rate Base Subject to Trending		18,728	148,205	166,933
Less: Deferred Taxes @ 12-31-89		4,783	12,413	17,196
Rate Base @ December 31, 1989		13,945	135,792	149,737

Schedule 1(C)
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1989 FERC TARIFF FILING
SUPPORTING DATA

TRANSITION RATE BASE
DEBT / EQUITY CAPITAL STRUCTURE

	($MM)	Percent
Long-Term Debt	1,975	27.1
Stockholders Equity	5,312	72.9
Total Capitalization	7,287	100.0

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1989 FERC TARIFF FILING
SUPPORTING DATA

DEBT / EQUITY CAPITAL STRUCTURE

The debt to equity capital structure used for 1988 and 1989, was determined from the following accounts of Balance Sheet as of December 31, 1988.

	$MM	%
Long-Term Debt	1,491	31.0%
Stockholders Equity	3,325	69.0%
Total Capitalization	4,816	100.0%

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1989 FERC TARIFF FILING
SUPPORTING DATA

DEBT EXPENSE

Debt Portion of Rate Base-End of Period (Sch. 1(B) Pg 8)	13,945
Parent's Embedded Debt Service Cost	10.0%
Debt Expense (1)	1,394
	==========

NOTE (1): In accordance with opinion 154-C, even though does not have any long-term debt on its own books, interest expense for the computation of the tax allowance and for cost of service purposes is the return on the debt portion of the rate base.

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1989 FERC TARIFF FILING
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FEDERAL & STATE INCOME TAX COMPUTATION

		$M
Net Inc Before Interest and Taxes	Sch 1(A)	16,593
Less Interest Expense	Sch 1(A)	1,394

Subtotal		15,198
Plus:		
Amort. of Deferred Return	Sch 1(A)	1,266
AFUDC Pre 84	Sch 1(A)	298
AFUDC Post 83	Sch 1(A)	55

Total Net Income Before State Income Taxes		16,818
State Income Tax Rate @ %		841

Total Net Income Before Federal Income Taxes		15,977
Federal Income Tax Rate		34.0%

Federal Income Tax Allowance		5,432
		========
State Income Tax		841
Federal Income Tax		5,432

Total Income Tax		6,273
		========

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1989 FERC TARIFF FILING
SUPPORTING DATA

INFLATION ADJUSTMENT

	1988	1989
Consumer Price Index (1)	4.4%	4.4%

NOTE (1): The CPI is a price index which measures the overall changes in the price level of a typical 'Market basket' of consumer goods. It is one of the options listed in footnote #36 on page 9 of FERC Opinion No. 154-B.

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Form 6

FERC TARIFF FILING DATA
CHANGES IN CARRIER PROPERTY $M (YEAR 1984)

	Acct	BAL 1-1-84	Additions	Sales	Other Adj.	BAL 12-31-84	Balance In Service
GATHERING LINES:							
Land	101	0	0	0	0	0	
Right of Way	102	214	1	0	1	216	21
Line Pipe	103	2,063	12	3	95	2,167	2,16
Line Pipe Fittings	104	193	4	2	13	208	20
Pipeline Construction	105	2,718	25	6	131	2,868	2,86
Buildings	106	24	2	0	9	35	3
Boilers	107	0	0	0	0	0	
Pumping Equipment	108	500	17	(15)	20	552	55
Machine Tools & Machinery	109	0	0	0	0	0	
Other Station Equipment	110	491	15	8	126	624	62
Oil Tanks	111	44	19	0	182	245	24
Delivery Facilities	112	17	0	(10)	5	32	3
Communication Systems	113	0	0	0	5	5	
Office Furniture & Equipment	114	5	0	0	3	8	
Vehicles&Other Work Equipment	115	536	88	174	4	454	454
Other Property	116	0	0	0	0	0	0
Total Gathering Lines		6,805	183	168	594	7,414	7,414
TRUNK LINES:							
Land	151	921	14	1	6	540	540
Right of Way	152	[illegible]	84	4	(10)	3,284	3,284
Line Pipe	153	21,593	0	63	(28)	21,502	21,502
Line Pipe Fittings	154	1,931	32	26	23	1,960	1,960
Pipeline Construction	155	40,398	13	115	294	40,590	40,590
Buildings	156	4,995	127	(12)	7	5,141	5,141
Boilers	157	0	0	0	0	0	0
Pumping Equipment	158	4,824	147	(211)	(2)	5,180	5,180
Machine Tools & Machinery	159	54	0	1	0	53	53
Other Station Equipment	160	19,556	482	644	27	19,421	19,421
Oil Tanks	161	8,180	58	37	1	8,202	8,202
Delivery Facilities	162	8,972	376	170	0	9,178	9,178
Communication Systems	163	1,123	65	49	(3)	1,136	1,136
Office Furniture & Equipment	164	1,303	32	21	0	1,314	1,314
Vehicles & OWE	165	2,492	285	109	0	2,668	2,668
Other Property	166	0	0	0	0	0	0
Total Trunk Lines		119,186	1,685	1,017	315	120,169	120,169
GENERAL:							
Land	171	0	0	0	0	0	0
Buildings	176	0	0	0	0	0	0
Machine Tools & Machinery	179	0	0	0	0	0	0
Communication Systems	183	0	0	0	0	0	0
Office Furniture & Equipment	184	514	26	(16)	0	556	556
Vehicles&Other Work Equipment	185	1,049	16	0	1,373	2,438	2,438
Other Property	186	0	0	0	0	0	0
Construction Work In Progress	187	1,306	[illegible]	2	(3)	2,493	
Total General		2,869	1,234	(14)	1,370	5,487	2,994
Grand Total		128,860	3,102	1,171	2,279	133,070	130,577
Less CWIP		1,306	1,192	2	(3)	2,493	
Property In Service		127,554	1,910	1,169	2,282	130,577	

Schedule [redacted]
(Pg 2 of [redacted]
Form 6

FERC TARIFF FILING DATA
CHANGES IN CARRIER PROPERTY $M (YEAR 1985)

GATHERING LINES:	Acct	BAL 1-1-85	Additions	Sales	Other Adj.	BAL 12-31-85	Balanc In Service
Land	101	0	0	0	0	0	[redacted]
Right of Way	102	216	87	1	(167)	135	[redacted]
Line Pipe	103	2,167	219	62	(1,086)	1,238	1.23
Line Pipe Fittings	104	208	31	6	(101)	132	13
Pipeline Construction	105	2,868	914	69	(2,053)	1,660	1,[redacted]
Buildings	106	35	30	(1)	(39)	27	[redacted]
Boilers	107	0	0	0	0	0	
Pumping Equipment	108	552	14	10	(253)	303	[redacted]
Machine Tools & Machinery	109	0	0	0	0	0	[redacted]
Other Station Equipment	110	624	200	12	(426)	386	38
Oil Tanks	111	245	0	0	(19)	226	22
Delivery Facilities	112	32	0	9	0	23	[redacted]
Communication Systems	113	5	0	0	0	5	[redacted]
Office Furniture & Equipment	114	8	0	0	0	8	
Vehicles&Other Work Equipment	115	454	117	84	(178)	309	30
Other Property	116	0	0	0	0	0	[redacted]
Total Gathering Lines		7,414	1,612	252	(4,322)	4,452	4,45
TRUNK LINES:							
Land	151	540	0	2	(20)	518	51
Right of Way	152	3,284	133	136	(84)	3,197	3,19
Line Pipe	153	21,502	20	2,203	(1,338)	17,981	17,[redacted]
Line Pipe Fittings	154	1,960	53	151	(127)	1,735	1,[redacted]
Pipeline Construction	155	40,590	214	2,387	(1,182)	37,255	37,255
Buildings	156	5,141	117	31	(182)	5,045	5,0
Boilers	157	0	0	0	0	0	[redacted]
Pumping Equipment	158	5,180	15	762	(216)	4,217	4,2
Machine Tools & Machinery	159	53	0	4	(2)	47	47
Other Station Equipment	160	19,421	587	601	(1,085)	18,322	18,[redacted]
Oil Tanks	161	8,202	259	64	(596)	7,801	7,8[redacted]
Delivery Facilities	162	9,178	1,210	185	317	10,520	10,520
Communication Systems	163	1,136	12	16	(71)	1,061	1,06
Office Furniture & Equipment	164	1,314	79	7	(17)	1,369	1,3[redacted]
Vehicles & OWE	165	2,668	161	111	(74)	2,644	2,6
Other Property	166	0	0	0	0	0	0
Total Trunk Lines		120,169	2,860	6,630	(4,687)	111,712	111,7[redacted]
GENERAL:							
Land	171	0	0	0	0	0	[redacted]
Buildings	176	0	0	0	0	0	[redacted]
Machine Tools & Machinery	179	0	0	0	0	0	0
Communication Systems	183	0	0	0	0	0	0
Office Furniture & Equipment	184	556	28	0	3	587	5[redacted]
Vehicles&Other Work Equipment	185	2,438	0	11	0	2,427	2,427
Other Property	186	0	0	0	0	0	0
Construction Work In Progress	187	2,493	(1,898)	0	(158)	437	[redacted]
Total General		5,487	(1,870)	11	(155)	3,451	3,014
Grand Total		133,070	2,602	6,893	(9,164)	119,615	119,1[redacted]
Less CWIP		2,493	(1,898)	0	(158)	437	
Property In Service		130,577	4,500	6,893	(9,006)	119,178	[redacted]

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Form 6

FERC TARIFF FILING DATA
CHANGES IN CARRIER PROPERTY $M (YEAR 1986)

GATHERING LINES:	Acct	BAL 1-1-86	Additions	Sales	Other Adj.	BAL 12-31-86	Balance In Servic
Land	101	0	8	0	0	8	
Right of Way	102	135	60	2	(71)	122	1
Line Pipe	103	1,238	127	18	71	1,418	1,4
Line Pipe Fittings	104	132	70	2	0	200	2
Pipeline Construction	105	1,660	677	21	2	2,318	2,3
Buildings	106	27	64	0	0	91	9
Boilers	107	0	0	0	0	0	
Pumping Equipment	108	303	180	9	1	475	4
Machine Tools & Machinery	109	0	0	0	0	0	
Other Station Equipment	110	386	172	6	3	555	55
Oil Tanks	111	226	219	0	0	445	44
Delivery Facilities	112	23	0	0	0	23	2
Communication Systems	113	5	0	0	0	5	
Office Furniture & Equipment	114	8	0	0	0	8	
Vehicles&Other Work Equipment	115	309	8	48	(8)	261	26
Other Property	116	0	0	0	0	0	
Total Gathering Lines		4,452	1,585	106	(2)	5,929	5,92
TRUNK LINES:							
Land	151	518	120	23	0	615	61
Right of Way	152	3,197	46	0	0	3,243	3,24
Line Pipe	153	17,981	378	13	15	18,361	18,36
Line Pipe Fittings	154	1,735	78	12	31	1,832	1,83
Pipeline Construction	155	37,255	2,300	8	(16)	39,531	39,53
Buildings	156	5,045	800	3	(7)	5,835	5,83
Boilers	157	0	0	0	0	0	
Pumping Equipment	158	4,217	117	20	(52)	4,262	4,26
Machine Tools & Machinery	159	47	0	0	2	49	4
Other Station Equipment	160	18,322	1,000	120	(155)	19,047	19,04
Oil Tanks	161	7,801	861	12	0	8,650	8,65
Delivery Facilities	162	10,520	4,094	2	194	14,806	14,80
Communication Systems	163	1,061	0	4	2	1,059	1,05
Office Furniture & Equipment	164	1,369	67	15	0	1,421	1,42
Vehicles & OWE	165	2,644	147	296	17	2,512	2,51
Other Property	166	0	0	0	0	0	
Total Trunk Lines		111,712	10,008	528	31	121,223	121,22
GENERAL:							
Land	171	0	0	0	0	0	
Building	176	0	0	0	0	0	
Machine Tools & Machinery	179	0	0	0	0	0	
Communication Systems	183	0	0	0	0	0	
Office Furniture & Equipment	184	587	139	13	2	715	71
Vehicles&Other Work Equipment	185	2,427	0	0	0	2,427	2,42
Other Property	186	0	0	0	0	0	
Construction Work In Progress	187	437	1,609	0	0	2,046	
Total General		3,451	1,748	13	2	5,188	3,14
Grand Total		119,615	13,341	647	31	132,340	130,29
Less CWIP		437	1,609	0	0	2,046	
Property In Service		119,178	11,732	647	31	130,294	

FERC TARIFF FILING DATA
CHANGES IN CARRIER PROPERTY $M (YEAR 1987)

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GATHERING LINES:	Acct	BAL 1-1-87	Additions	Sales	Other Adj.	BAL 12-31-87	Balance In Servi
Land	101	8	0	0	0	8	[illegible]
Right of Way	102	122	5	0	0	127	12
Line Pipe	103	1,418	19	6	0	1,431	1,
Line Pipe Fittings	104	200	7	1	0	206	[illegible]
Pipeline Construction	105	2,318	66	4	0	2,380	2,38
Buildings	106	91	6	0	0	97	[illegible]
Boilers	107	0	0	0	0	0	[illegible]
Pumping Equipment	108	475	31	5	(5)	496	49
Machine Tools & Machinery	109	0	0	0	0	0	(
Other Station Equipment	110	555	96	2	(1)	648	6
Oil Tanks	111	445	0	0	0	445	4
Delivery Facilities	112	23	0	2	0	21	21
Communication Systems	113	5	0	0	0	5	[illegible]
Office Furniture & Equipment	114	8	50	0	0	58	[illegible]
Vehicles&Other Work Equipment	115	261	3	64	(93)	107	1
Other Property	116	0	29	0	86	115	115
Total Gathering Lines		5,929	312	84	(13)	6,144	6,1
TRUNK LINES:							
Land	151	615	125	0	(1)	739	7
Right of Way	152	3,243	108	0	55	3,403	3,4
Line Pipe	153	18,361	425	1	(46)	18,739	18,739
Line Pipe Fittings	154	1.832	149	1	(5)	1,975	1,97
Pipeline Construction	155	39,531	8,162	3	(41)	47,649	47,6
Buildings	156	5,835	378	2	(37)	6,174	6,1
Boilers	157	0	0	0		0	0
Pumping Equipment	158	4,262	35	0	3	4,300	4,3
Machine Tools & Machinery	159	49	0	0	(50)	(1)	(
Other Station Equipment	160	19,047	1,135	0	(435)	19,747	19,747
Oil Tanks	161	8,650	193	0	440	9,283	9,283
Delivery Facilities	162	14,806	1,486	0	173	16,465	16,46
Communication Systems	163	1,059	327	0	1	1,387	1,38
Office Furniture & Equipment	164	1,421	63	48	(135)	1,301	1,301
Vehicles & OWE	165	2,512	84	158	(1,570)	868	86
Other Property	166	0	186	0	1,672	1,858	1,85
Total Trunk Lines		121,223	12,853	213	24	133,887	133,887
GENERAL:							
Land	171	0	0	0	0	0	0
Buildings	176	0	0	0	0	0	[illegible]
Machine Tools & Machinery	179	0	0	0	0	0	[illegible]
Communication Systems	183	0	0	0	0	0	0
Office Furniture & Equipment	184	715	16	0	0	731	731
Vehicles&Other Work Equipment	185	2,427	0	0	0	2,427	2,42
Other Property	186	0	0	0	0	0	(
Construction Work In Progress	187	2,046	(229)	0	(11)	1,806	
Total General		5,188	(213)	0	(11)	4,964	3,158
Grand Total		132,340	12,952	297	0	144,995	143,189
Less CWIP		2,046	(229)	0	(11)	1,806	
Property In Service		130,294	13,181	297	11	143,189	

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FERC TARIFF FILING DATA
CHANGES IN CARRIER PROPERTY $M (YEAR 1988)

	Acct	BAL 1-1-88	Additions	Sales	Other Adj.	BAL 12-31-88	Balance In Servic
GATHERING LINES:							
Land	101	8	0	0	0	8	
Right of Way	102	127	0	0	0	127	1
Line Pipe	103	1,431	3	11	0	1,423	1,4
Line Pipe Fittings	104	206	5	8	0	203	2
Pipeline Construction	105	2,380	31	20	0	2,391	2,3
Buildings	106	97	3	3	0	97	
Boilers	107	0	0	0	0	0	
Pumping Equipment	108	496	16	11	0	501	5
Machine Tools & Machinery	109	0	0	0	0	0	
Other Station Equipment	110	648	12	2	(13)	645	64
Oil Tanks	111	445	0	0	0	445	44
Delivery Facilities	112	21	6	0	0	27	2
Communication Systems	113	5	0	0	6	11	1
Office Furniture & Equipment	114	58	2	0	0	60	6
Vehicles&Other Work Equipment	115	107	(10)	62	(1)	34	3
Other Property	116	115	1	3	24	137	13
Total Gathering Lines		6,144	69	120	16	6,109	6,10
TRUNK LINES:							
Land	151	739	6	0	0	745	74
Right of Way	152	3,403	1	0	0	3,404	3,40
Line Pipe	153	18,739	152	49	0	18,842	18,84
Line Pipe Fittings	154	1,975	22	8	0	1,989	1,98
Pipeline Construction	155	47,649	2,662	45	0	50,266	50,26
Buildings	156	6,174	132	4	(5)	6,297	6,29
Boilers	157	0	0	0	0	0	
Pumping Equipment	158	4,300	36	20	1	4,317	4,317
Machine Tools & Machinery	159	(1)	0	0	0	(1)	(1
Other Station Equipment	160	19,747	563	7	569	20,872	20,872
Oil Tanks	161	9,283	221	1	(557)	8,946	8,946
Delivery Facilities	162	16,465	1,314	0	(482)	17,297	17,297
Communication Systems	163	1,387	43	32	5	1,403	1,403
Office Furniture & Equipment	164	1,301	106	(29)	(1)	1,435	1,435
Vehicles & OWE	165	868	(3)	231	(43)	591	591
Other Property	166	1,858	200	36	10	2,032	2,032
Total Trunk Lines		133,887	5,455	404	(503)	138,435	138,435
GENERAL:							
Land	171	0	0	0	0	0	0
Buildings	176	0	0	0	0	0	0
Machine Tools & Machinery	179	0	0	0	0	0	0
Communication Systems	183	0	0	0	0	0	0
Office Furniture & Equipment	184	731	88	0	0	819	819
Vehicles&Other Work Equipment	185	2,427	0	0	0	2,427	2,427
Other Property	186	0	0	0	0	0	0
Construction Work In Progress	187	1,806	755	0	(158)	2,403	
Total General		4,964	843	0	(158)	5,649	3,246
Grand Total		144,995	6,367	524	(645)	150,193	147,790
Less CWIP		1,806	755	0	(158)	2,403	
Property In Service		143,189	5,612	524	(487)	147,790	

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FERC TARIFF FILING DATA
CHANGES IN CARRIER PROPERTY $M (thru 6/30/89)

GATHERING LINES:	Acct	BAL 1-1-89	Additions	Sales	Other Adj.	BAL 06-30-89	Balan In Servi
Land	·101	8	0	0	0	8	
Right of Way	·102	127	0	1	0	128	
Line Pipe	·103	1,423	0	3	0	1,420	1.
Line Pipe Fittings	104	203	0	1	0	202	
Pipeline Construction	·105	2,391	0	3	1	2,389	2
Buildings	·106	97	0	0	0	97	
Boilers	·107	0	0	0	0	0	
Pumping Equipment	·108	501	0	2	0	499	
Machine Tools & Machinery	·109	0	0	0	0	0	
Other Station Equipment	·110	645	0	0	0	645	6
Oil Tanks	·111	445	0	0	0	445	
Delivery Facilities	·112	27	0	0	0	27	
Communication Systems	·113	11	0	0	(75)	(64)	(
Office Furniture & Equipment	·114	60	0	0	0	60	
Vehicles&Other Work Equipment	·115	34	21	0	(3)	52	
Other Property	·116	137	0	0	1	138	1
Total Gathering Lines		6.109	21	10	(76)	6,044	6
TRUNK LINES:							
Land	·151	748	0	0	0	748	7
Right of Way	·152	3,404	0	0	0	3,404	3
Line Pipe	·153	18,842	0	75	0	18,767	18,
Line Pipe Fittings	·154	1,989	0	7	0	1,982	1,9
Pipeline Construction	·155	50,266	0	31	2	50,237	50
Buildings	·156	6,297	0	0	0	6,297	6
Boilers	·157	0	0	0	0	0	
Pumping Equipment	·158	4,317	0	0	0	4,317	4,3
Machine Tools & Machinery	·159	(1)	0	0	0	(1)	
Other Station Equipment	·160	20,872	0	3	0	20,869	20,
Oil Tanks	·161	8,946	0	0	(1)	8,945	8.9
Delivery Facilities	·162	17,297	0	0	2	17,299	17
Communication Systems	·163	1,403	0	0	152	1,555	1
Office Furniture & Equipment	·164	1,435	0	8	(3)	1,424	1,4
Vehicles & OWE	·165	591	0	28	(1)	562	
Other Property	·166	2,032	0	2	3	2,033	2,
Total Trunk Lines		138,435	0	154	154	138,435	138,4
GENERAL:							
Land	·171	0	0	0	0	0	
Buildings	·176	0	0	0	0	0	
Machine Tools & Machinery	·179	0	0	0	0	0	
Communication Systems	·183	0	0	0	0	0	
Office Furniture & Equipment	·184	819	0	0	(4)	815	81
Vehicles&Other Work Equipment	·185	2,427	0	0	0	2,427	2,
Other Property	·186	0	0	0	0	0	
Construction Work In Progress	[illegible]	2,403	3,300	0	4	5,707	
Total General		5,649	3,300	0	0	8,949	3,
Grand Total		150,193	3,321	164	78	153,428	147,72
Less CWIP		2,403	3,300	0	4	5,707	
Property In Service		147,790	21	164	[illegible]	[illegible]	

1989 FERC TARIFF FILING
SUPPORTING DATA

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CALCULATION OF DEFERRED RETURN
$M

		1983	1984	1985	1986	1987	1988	1989
1 Beg Bal of Property Sch 1 (B)			41,439	40,776	36,442	43,377	50,244	51,799
2 Beg Bal of Deferred Return Sch 1 (B)			73,377	77,559	81,906	86,491	87,254	92,337
3 Total Rate Base Subject to Trending	1+2		114,816	118,335	118,348	129,868	137,498	144,136
4 Inflation Rate			3.8%	4.0%	3.8%	1.1%	4.4%	4.4%
5 Additions to Rate Base	3*4		4,363	4,733	4,497	1,429	6,050	6,342
6 Beg Bal of Deferred Return			73,377	77,559	81,906	86,491	87,254	92,337
7 Additions to Rate Base			4,363	4,733	4,497	1,429	6,050	6,342
8 Deferred Return Available	6+7		77,740	82,292	86,403	87,920	93,304	98,679
9 Less 1983 End Balance Sch 1(B) pg 3			73,377	73,377	73,377	73,859	73,859	73,859
10 Def. Return Available for Recovery	8-9		4,363	8,915	13,026	14,061	19,445	24,820
11 Remaining Years			24.1	23.1	22.1	21.1	20.1	19.6
12 Current Year Amortization	10/11		181	386	589	666	967	1,266
End Bal of Deferred Return	8-12		77,559	81,906	85,814	87,253	92,337	97,413
Plus Pre 84 Bal					482			
Plus Post 83 Bal					195			
Total End Bal of Deferred Return			77,559	81,906	86,491	87,253	92,337	97,413

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FERC TARIFF FILING
SUPPORTING DATA
CHANGES IN ACCRUED DEPRECIATION (YEAR 1984)

GATHERING LINES:	Acct	BAL 1-1-84	Depr.	Sales	Other Adj.	BAL 12-31-84
Right of Way	102	129	7		1	137
Line Pipe	103	1,502	65	1	107	1,673
Line Pipe Fittings	104	124	7		12	143
Pipeline Construction	105	1,348	95	9	103	1,537
Buildings	106	10	1		12	23
Boilers	107					0
Pumping Equipment	108	476	28	2	22	522
Machine Tools & Machinery	109					0
Other Station Equipment	110	164	20	4	41	221
Oil Tanks	111	42	1		192	235
Delivery Facilities	112	(4)	1	(11)	4	12
Communication Systems	113				1	1
Office Furniture & Equipment	114	5			3	8
Vehicles&Other Work Equipment	115	315	89	89	(22)	293
Other Property	116					0
Total Gathering Lines		4,111	312	94	476	4,805
TRUNK LINES:						
Right of Way	152	1,980	45	3	(1)	2,021
Line Pipe	153	17,683	554	33	(8)	18,198
Line Pipe Fittings	154	1,009	60	19	0	1,050
Pipeline Construction	155	27,790	1,395	(35)	3	29,223
Buildings	156	2,486	133	9	1	2,611
Boilers	157	0	0	0	0	0
Pumping Equipment	158	2,255	162	49	(3)	2,365
Machine Tools & Machinery	159	68	0	0	0	68
Other Station Equipment	160	7,319	685	364	(18)	7,622
Oil Tanks	161	5,050	190	2	(5)	5,233
Delivery Facilities	162	3,501	300	148	(1)	3,654
Communication Systems	163	654	62	53	0	663
Office Furniture & Equipment	164	438	53	1	(12)	478
Vehicles & OWE	165	1,538	271	88	(3)	1,718
Other Property	166	0	0	0	0	0
Total Trunk Lines		71,769	3,910	732	(45)	74,902
GENERAL:						
Buildings	176					0
Machine Tools & Machinery	179					0
Communication Systems	183					0
Office Furniture & Equipment	184	204	38			242
Vehicles&Other Work Equipment	185	678	115		47	840
Other Property	186					0
Total General		882	153	0	47	1,082
Grand Total		76,762	4,375	828	478	80,789

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FERC TARIFF FILING
SUPPORTING DATA
CHANGES IN ACCRUED DEPRECIATION (YEAR 1985)

GATHERING LINES:	Acct	BAL 1-1-85	Depr.	Sales	Other Adj.	BAL 12-31-85
Right of Way	102	137	9	1	(50)	95
Line Pipe	103	1,673	70	56	(513)	1,174
Line Pipe Fittings	104	143	8	2	(51)	98
Pipeline Construction	105	1,537	117	67	(523)	1,064
Buildings	106	23	2	(1)	(5)	21
Boilers	107	0		0		0
Pumping Equipment	108	522	25	11	(232)	304
Machine Tools & Machinery	109	0		0		0
Other Station Equipment	110	221	26	9	(82)	156
Oil Tanks	111	235	1	0	(1)	235
Delivery Facilities	112	12	1	7	(1)	5
Communication Systems	113	1	0	0		1
Office Furniture & Equipment	114	8	0	0		8
Vehicles&Other Work Equipment	115	293	89	(4)	(166)	220
Other Property	116	0		0		0
Total Gathering Lines		4,805	348	148	(1,624)	3,381
TRUNK LINES:						
Right of Way	152	2,021	38	0	(104)	1,955
Line Pipe	153	18,198	428	7	(3,045)	15,574
Line Pipe Fittings	154	1,050	55	35	(116)	954
Pipeline Construction	155	29,223	1,191	57	(2,539)	27,818
Buildings	156	2,611	134	18	(120)	2,607
Boilers	157	0		0	0	0
Pumping Equipment	158	2,365	160	767	(94)	1,664
Machine Tools & Machinery	159	66	0	2	(2)	62
Other Station Equipment	160	7,622	679	579	(306)	7,416
Oil Tanks	161	5,233	196	5	(481)	4,943
Delivery Facilities	162	3,654	329	129	55	3,909
Communication Systems	163	663	60	1	(55)	667
Office Furniture & Equipment	164	478	55	4	(12)	517
Vehicles & OWE	165	1,718	229	17	(114)	1,816
Other Property	166	0		0	0	0
Total Trunk Lines		74,902	3,554	1,621	(6,933)	69,902
GENERAL:						
Buildings	176	0				0
Machine Tools & Machinery	179	0				0
Communication Systems	183	0				0
Office Furniture & Equipment	184	242	29	0	0	271
Vehicles&Other Work Equipment	185	840	183	6	(7)	1,010
Other Property	186	0				0
Total General		1,082	212	6	(7)	1,281
Grand Total		80,789	4,114	1,775	(8,564)	74,564

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FERC TARIFF FILING
SUPPORTING DATA
CHANGES IN ACCRUED DEPRECIATION (YEAR 1986)

	Acct	BAL 1-1-86	Depr.	Sales	Other Adj.	BAL 12-31-86
GATHERING LINES:						
Right of Way	102	95	5	2	0	98
Line Pipe	103	1,174	37	18	(12)	1,181
Line Pipe Fittings	104	98	4	2	0	100
Pipeline Construction	105	1,064	54	19	0	1,099
Buildings	106	21	1	0	0	22
Boilers	107	0	0	0	0	0
Pumping Equipment	108	304	8	6	0	306
Machine Tools & Machinery	109	0	0	0	0	0
Other Station Equipment	110	156	14	7	(3)	160
Oil Tanks	111	235	0	0	0	235
Delivery Facilities	112	5	1	0	0	6
Communication Systems	113	1	0	0	0	1
Office Furniture & Equipment	114	8	0	0	0	8
Vehicles&Other Work Equipment	115	220	22	35	0	207
Other Property	116	0		0		0
Total Gathering Lines		3,381	146	89	(15)	3,423
TRUNK LINES:						
Right of Way	152	1,955	43	0	0	1,998
Line Pipe	153	15,574	329	12	0	15,891
Line Pipe Fittings	154	954	49	12	7	998
Pipeline Construction	155	27,818	940	8	14	28,764
Buildings	156	2,607	132	3	0	2,736
Boilers	157	0	0	0	0	0
Pumping Equipment	158	1,664	134	18	(7)	1,773
Machine Tools & Machinery	159	62	0	13	0	49
Other Station Equipment	160	7,416	654	114	1	7,957
Oil Tanks	161	4,943	179	21	(1)	5,100
Delivery Facilities	162	3,909	358	2	(1)	4,264
Communication Systems	163	667	54	3	0	718
Office Furniture & Equipment	164	517	57	16	1	559
Vehicles & OWE	165	1,816	166	232	3	1,753
Other Property	166	0	0	0	0	0
Total Trunk Lines		69,902	3,095	454	17	72,560
GENERAL:						
Buildings	176	0				
Machine Tools & Machinery	179	0				0
Communication Systems	183	0				0
Office Furniture & Equipment	184	271	34	8	0	297
Vehicles&Other Work Equipment	185	1,010	182	(6)	0	1,198
Other Property	186	0				0
Total General		1,281	216	2	0	1,495
Grand Total		74,564	3,457	545	2	77,478

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FERC TARIFF FILING
SUPPORTING DATA
CHANGES IN ACCRUED DEPRECIATION (YEAR 1987)

GATHERING LINES:	Acct	BAL 1-1-87	Depr.	Sales	Other Adj.	BAL 12-31-87
Right of Way	102	98	4	0	0	102
Line Pipe	103	1,181	41	6	(13)	1,203
Line Pipe Fittings	104	100	7	0	0	107
Pipeline Construction	105	1,099	76	4	0	1,171
Buildings	106	22	2	0	0	24
Boilers	107	0	0	0	0	0
Pumping Equipment	108	306	20	5	(7)	314
Machine Tools & Machinery	109	0	0	0	0	0
Other Station Equipment	110	160	20	1	0	179
Oil Tanks	111	235	6	0	0	241
Delivery Facilities	112	6	1	2	0	5
Communication Systems	113	1	0	0	0	1
Office Furniture & Equipment	114	8	0	0	0	8
Vehicles&Other Work Equipment	115	207	22	54	(96)	79
Other Property	116	0	2	0	96	98
Total Gathering Lines		3,423	201	72	(20)	3,532
TRUNK LINES:						
Right of Way	152	1,998	62	0	43	2,103
Line Pipe	153	15,891	342	13	(38)	16,182
Line Pipe Fittings	154	998	240	(8)	6	1,252
Pipeline Construction	155	28,764	774	(10)	(23)	29,525
Buildings	156	2,736	145	2	(19)	2,860
Boilers	157	0	0	0	0	0
Pumping Equipment	158	1,773	136	0	0	1,909
Machine Tools & Machinery	159	49	0	0	(50)	(1)
Other Station Equipment	160	7,957	678	5	(12)	8,618
Oil Tanks	161	5,100	182	0	(47)	5,235
Delivery Facilities	162	4,264	512	0	76	4,852
Communication Systems	163	718	42	17	(25)	718
Office Furniture & Equipment	164	559	58	0	0	617
Vehicles & OWE	165	1,753	97	129	(1,141)	580
Other Property	166	0	57	0	1,191	1.248
Total Trunk Lines		72,560	3,325	148	(39)	75,698
GENERAL:						
Buildings	176	0				0
Machine Tools & Machinery	179	0				0
Communication Systems	183	0				0
Office Furniture & Equipment	184	297	36	0	0	333
Vehicles&Other Work Equipment	185	1,198	182	0	(6)	1,374
Other Property	186	0	0	0	6	6
Total General		1,495	218	0	0	1.713
Grand Total		77,478	3,744	220	(59)	80.943

Schedule
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From 6

FERC TARIFF FILING
SUPPORTING DATA
CHANGES IN ACCRUED DEPRECIATION (YEAR 1988)

	Acct	BAL 1-1-88	Depr.	Sales	Other Adj.	BAL 12-31-88
GATHERING LINES:						
Right of Way	102	102	5	0	0	107
Line Pipe	103	1,203	17	11	(4)	1,205
Line Pipe Fittings	104	107	5	8	0	104
Pipeline Construction	105	1,171	70	20	0	1,221
Buildings	106	24	5	3	0	26
Boilers	107	0	0	0	0	0
Pumping Equipment	108	314	17	11	(3)	317
Machine Tools & Machinery	109	0	0	0	0	0
Other Station Equipment	110	179	30	3	4	210
Oil Tanks	111	241	6	0	0	247
Delivery Facilities	112	5	2	0	0	7
Communication Systems	113	1	0	0	1	2
Office Furniture & Equipment	114	8	0	0	0	8
Vehicles&Other Work Equipment	115	79	(8)	56	6	21
Other Property	116	98	0	3	3	98
Total Gathering Lines		3,532	149	115	7	3,573
TRUNK LINES:						
Right of Way	152	2,103	57	0	0	2,160
Line Pipe	153	16,182	47	50	(59)	16,120
Line Pipe Fittings	154	1,252	49	7		1,294
Pipeline Construction	155	29,525	655	43	(2)	30,135
Buildings	156	2,860	174	4	(1)	3,029
Boilers	157	0	0	0		0
Pumping Equipment	158	1,909	112	20	1	2,002
Machine Tools & Machinery	159	(1)	0	0		(1)
Other Station Equipment	160	8,618	581	2	(124)	9,073
Oil Tanks	161	5,235	168	1	(1)	5,401
Delivery Facilities	162	4,852	893	0	(138)	5,607
Communication Systems	163	718	47	32	4	737
Office Furniture & Equipment	164	617	89	(23)		729
Vehicles & OWE	165	580	42	188	(4)	430
Other Property	166	1,248	42	37	6	1,259
Total Trunk Lines		75,698	2,956	361	(318)	77,975
GENERAL:						
Buildings	176	0				0
Machine Tools & Machinery	179	0				0
Communication Systems	183	333	37	0	0	370
Office Furniture & Equipment	184	1,374	182	0	0	1,556
Vehicles&Other Work Equipment	185	0	0	0	0	0
Other Property	186	6	0	0	(6)	0
Total General		1,713	219	0	(6)	1,926
Grand Total		80,943	3,324	476	(317)	83,474

1989 FERC TARIFF FILING
SUPPORTING DATA

COMPARATIVE EXPENSES

GENERAL EXPENSE:	($M) 1989 (1)
Total General Expense- Sch. 1(M) Pg 1	24,507
Less: Account 540 - Depreciation Sch. 1(M) Pg 1	3,421
Less: Account 580 - Pipeline Taxes- Sch. 1(M) Pg 1	3,187
General Expense (Less Depreciation and Taxes)	17,899

NOTE (1): Fiscal Yr. 6-30-89

1989 FERC TARIFF FILING
SUPPORTING DATA

Schedule 1(M)
(Pg 1 of 2)

COMPARATIVE EXPENSES

DESCRIPTION	<------------- 1988	---($M)--- ADJUST.	-----------> 1989 (2)
Operating Expenses			
300 Salaries and Wages	4,035	115	4,150
310 Supplies and Expenses	922	10	932
320 Outside Services	668	(11)	657
330 Operating Fuel and Power	6,397	260	6,657
340 Oil Losses and Shortages	(304)	233	(71)
Total Operating Expenses	11,718	607	12,325
Maintenance Expenses			
400 Salaries and Wages	3,679	207	3,886
410 Supplies and Expenses	1,738	102	1,840
420 Outside Services	5,252	915	6,167
430 Maintenance Materials	481	62	543
Total Maintenance Expenses	11,150	1,286	12,436
General Expenses (1)			
500 Salaries and Wages	3,580	63	3,643
510 Supplies and Expenses	947	124	1,071
520 Outside Services	7,353	15	7,368
530 Rentals	708	57	765
540 Depreciation and Amortization	3,317	104	3,421
550 Pensions and Benefits	2,179	320	2,499
560 Insurance	1,135	(78)	1,057
570 Casualty and Other Losses	2,150	(654)	1,496
580 Pipeline Taxes	3,012	175	3,187
Total General Expenses	24,381	126	24,507
Total Expenses	47,249	2,019	49,268
Trunk Volumes (MBBLS)	184,828	********	N.A.
Barrel Miles (MM)	14,834	(14,834)	N.A.

NOTE (1): Headquarters Allocated Based on Massachusetts Formula.

NOTE (2): Fiscal Yr. 6-30-89

Schedule 1(h)
(Pg 1 of 1)

1989 FERC TARIFF FILING
SUPPORTING DATA

WORKING CAPITAL 1982-1988

Year	Form 6 Account	Account Balance	Non Carrier	Net Balance	Annual Change
1982					
Oil Inventory	16	0		0	
Mat & Supplies	17	674		674	
Prepayments	18	21		21	
Total Working Cap		695	0	695	
1983					
Oil Inventory	16	0		0	
Mat & Supplies	17	552		552	
Prepayments	18	74		74	
Total Working Cap		626	0	626	(69)
1984					
Oil Inventory	16	0		0	
Mat & Supplies	17	566		566	
Prepayments	18	114		114	
Total Working Cap		680	0	680	54
1985					
Oil Inventory (1)	16	289	289	0	
Mat & Supplies	17	622	494	128	
Prepayments	18	153		153	
Total Working Cap		1,064	783	281	(399)
1986					
Oil Inventory (1)	16	886	886	0	
Mat & Supplies	17	614	253	361	
Prepayments	18	134		134	
Total Working Cap		1,634	1,139	495	214
1987					
Oil Inventory (1)	16	756	756	0	
Mat & Supplies	17	611	183	428	
Prepayments	18	151		151	
Total Working Cap		1,518	939	579	84
1988					
Oil Inventory (1)	16	451	451	0	
Mat & Supplies	17	745	203	542	
Prepayments	18	87		87	
Total Working Cap		1,283	654	629	50

(1) Represents Oil Inventory @ Terminal (Non-Carrier)

Schedule
(Pg 6 of

FERC TARIFF FILING
SUPPORTING DATA
CHANGES IN ACCRUED DEPRECIATION (thru 6/30/89)

	Acct	BAL 1-1-89	Depr.	Sales	Other Adj.	BAL 06-30-89
GATHERING LINES:						
Right of Way	102	107	2	1	0	108
Line Pipe	103	1,205	8	1	0	1,212
Line Pipe Fittings	104	104	3	1	0	106
Pipeline Construction	105	1,221	35	4	1	1,253
Buildings	106	26	2	0	0	28
Boilers	107	0	0	0	0	0
Pumping Equipment	108	317	8	1	0	324
Machine Tools & Machinery	109	0	0	0	0	0
Other Station Equipment	110	210	15	0	0	225
Oil Tanks	111	247	3	0	0	250
Delivery Facilities	112	7	1	0	0	8
Communication Systems	113	2	0	2	(3)	(3)
Office Furniture & Equipment	114	8	0	0	0	8
Vehicles&Other Work Equipment	115	21	17	0	(1)	37
Other Property	116	98	6	0	(1)	103
Total Gathering Lines		3,573	100	10	(4)	3,659
TRUNK LINES:						
Right of Way	152	2,160	27	0	0	2,187
Line Pipe	153	16,120	35	71	1	16,085
Line Pipe Fittings	154	1,294	24	6	0	1,312
Pipeline Construction	155	30,135	279	30	0	30,384
Buildings	156	3,029	86	0	0	3,115
Boilers	157	0	0	0	0	0
Pumping Equipment	158	2,002	57	0	0	2,059
Machine Tools & Machinery	159	(1)	0	0	0	(1)
Other Station Equipment	160	9,073	303	2	0	9,374
Oil Tanks	161	5,401	83	0	0	5,484
Delivery Facilities	162	5,607	472	0	1	6,080
Communication Systems	163	737	19	0	5	761
Office Furniture & Equipment	164	729	48	7	(1)	769
Vehicles & OWE	165	430	2	24	(1)	407
Other Property	166	1,259	20	2	2	1,279
Total Trunk Lines		77,975	1,455	142	7	79,295
GENERAL:						
Buildings	176	0	0	0	0	0
Machine Tools & Machinery	179	0	0	0	0	0
Communication Systems	183	0	0	0	0	0
Office Furniture & Equipment	184	370	20	0	0	390
Vehicles&Other Work Equipment	185	1,556	91	0	0	1,647
Other Property	186	0	0	0	0	0
Total General		1,926	111	0	0	2,037
Grand Total		83,474	1,666	152	3	84,991

Schedule 2

1989 FERC TARIFF FILING
SUPPORTING DATA

OPERATING REVENUES

DESCRIPTION	<------- REVENUE ($M) -------> Test yr. At Existing Rates		Test yr. At Proposed Rates
Total Operating Revenue (1)	64,965	2,515	67,480

Test year based on Fiscal yr. ending 6-30-89, and annualized tariff increases

"Meeting the Challenge of the New Competitive Environment"

Remarks By

Max Feldman
Vice President, Transmission System Planning
TransCanada PipeLines

1991 CPA Pipeline Conference:
Pipelines in a Changing Environment

Calgary, Alberta
May 15, 1991

Meeting the Challenge of the New Competitive Environment

Introduction

On behalf of TransCanada PipeLines, thank you for this invitation to speak to you today. The Canadian Petroleum Association and its member companies have played a major role in influencing the changes that have occurred in the natural gas industry during the past several years, and it is an honour to be asked to participate in its activities. I much prefer this forum to one that I have become only too familiar with during the past four years, namely appearing before the NEB at rate or facilities proceedings in which I was often cross-examined by lawyers representing the CPA!

This conference is titled "Pipelines in a Changing Environment". However, I'd like to emphasize that pipelines are an integral part of the larger natural gas industry. If natural gas is to reach its full potential in the North American energy market, it will require a joint partnership between producers, marketers, pipelines and utilities, to meet the challenge of the new competitive environment. We are all in this together and need to understand each others challenges because the challenges of each of us are the challenges of all of us.

As you know, the mid 1980's was the beginning of the new age for natural gas in Canada. On Nov. 1, 1984, the federal government terminated its administration of gas export prices. A year later, with the Halloween Agreement, domestic naural gas prices were deregulated and the transition to open access on Canadian pipelines began. These were heady times for the natural gas industry because finally the deregulation of natural gas prices would mean that the clean burning fuel could be competitive with alternative energy supplies and U.S. sourced gas supplies. The Canadian industry would be able to expand and prosper to meet growing demands both in Canada and the U.S.

The promise of expanding domestic markets and increased exports was to dissipate the surplus of domestic supplies that had been accumulating over the years due to regulated pricing and the surplus test. Though it was generally recognized that gas prices would falter initially because of the surplus, it was genuinely believed that increased access to existing and new markets would result in strong prices and would provide the basis for a healthy and thriving exploration, production, marketing and transmission industry.

As we all know, the world did not unfold as we expected. Regulatory uncertainties and delays in pipeline expansions frustrated the needed flow of additional volumes to market. Continued regulation of gas transactions on both sides of the border also frustrated the movement of additional volumes. Transportation rate designs and terms of access, particularly in the U.S., inhibited the efficient use of pipeline space.

The primary result of these delays, distortions, and uncertainties as well as other economic factors was continued productive over capacity and depressed natural gas prices. Though tremendous strides on both sides of the border have been made recently to alleviate these barriers, gas prices in recent months have been at their lowest levels in the last couple of years. This is due in part to the recession and warmer than normal temperatures. In fact, we estimate that between 20 and 25 Bcf of Eastern Canadian demand did not materialize because of warm weather over the last year.

Natural gas consumers have greatly benefitted from deregulation and depressed prices. Between 1985 and 1990 the Alberta border price of natural gas has decreased by an average of 37 per cent. This, however, has occurred at the expense of the producing community. Times have been tough for Canadian producers. Times however, I believe, are improving.

Pipeline expansions are now finally happening. Natural gas regulators on both sides of the border are stepping back more and more to let the market work. Natural gas markets are expanding in terms of geography and sector. The U.S. Northeast within the next year will grow to become a major market for Canadian gas. The non-utility electrical generation market, in general, holds tremendous promise for natural gas. Natural gas exports have climbed. However, with the completion of the St. Clair Pipeline, the potential for U.S. imports into Canada has also increased. This cross border flow of natural gas is a prime indicator of the workings of a competitive North American gas market.

With all of these occurrences, Canadian natural gas producers, marketers and transporters are now poised to meet the challenges of the new competitive environment for natural gas and to reap the benefits.

Let me now focus on the challenges, as I see them, faced by the Canadian natural gas industry, as a whole, in the areas of:

(1) Regulation
(2) Transportation Capacity,
(3) Quality of Service, and
(4) Gas Supply.

Understanding and meeting these challenges will ensure the healthy future of the Canadian natural gas industry.

(1) Regulation

With deregulation and the continuing development of the North American transportation network, Canadian producers and marketers will not only face competition from their Canadian brothers but will have to compete with their U.S. sisters. Consequently, the delivered price of natural gas will be a key determinant in maintaining and gaining markets for Canadian gas supplies. In addition, the price netted back to the producer will have a direct bearing on the continued exploration and development of new supplies.

Because transmission costs reflect a significant portion of the delivered price of gas, it is necessary that transmission costs be minimized to maximize producer netbacks.

TransCanada recognizes this and we have through our design and operating efforts been able to operate the TransCanada system at virtual capacity for the last few years. This has translated directly into lower unit costs for our shippers. Our challenge for the future will be to maintain this high level of capacity utilization, particularly as our system expands. In this regard, we are staying in frequent touch with our shippers to ensure that our capacity increases match as closely as possible our customers' requirements. We are also currently examining our Firm Service Tendered service (a load balancing mechanism) and alternatives to it, such as storage.

Despite the fact that we are in an expansion phase, with new costs being higher than the historical depreciated costs that are used to determine the tolls for our service, TransCanada projects that its tolls will be less, in real terms, than tolls charged in 1977. The projected tolls on this slide assume expansion of 400 MMcfd over and above currently approved expansions.

Apart from the cost of transportation, Canadian transportation rate design is also pertinent to the issue of competitiveness. TransCanada's tolls have always been calculated on a rolled-in basis. This methodology, as you know, was reaffirmed by the National Energy Board last November. In TransCanada's view, rolled-in tolls provide equitable treatment to any shipper who wishes to use the system. All shippers, new and old, domestic and export are treated the same and have equal opportunities on our system. This promotes open access to our system and means that no shipper has a competitive advantage over another in transporting gas on the TransCanada system.

While on the topic of rate design, the Independent Petroleum Association of America (IPAA) in the U.S. is posing a challenge to the Canadian gas industry. They claim that Canadian gas is competitively advantaged because of the full fixed variable (FFV) rate design utilized by Canadian pipelines. I should note that CPA and all other interested parties at TransCanada's rate cases have supported the use of FFV for our open-access transportation system.

The IPAA argues that because U.S. pipelines' rates are determined on the basis of a modified fixed variable rate design where certain fixed costs are shifted into the commodity rate, a preference for Canadian gas supplies is created. This preference results because, they argue, customers choose their gas supplies solely on the basis of commodity prices. Given this argument, the IPAA has asked both FERC and the DOE to make adjustments to U.S. pipeline rates which transport Canadian gas to create a "level playing field". IPAA is also a major force behind attempts to enact legislation which would, at a minimum, delay further exports.

The IPAA argument appears to be gaining some momentum. The issue has been raised in the context of FERC's Comparability of Services Notice of Proposed Rulemaking (the Mega NOPR) where the need is recognized to create a "level playing field" with respect to Canadian gas. Chairman Allday has indicated that one of his priorities for the next year is to ensure that Canadian Gas gets no advantage over U.S. gas. Recently, FERC allowed applicants in the Northeast projects to utilize the rate design they originally requested. In some cases this is FFV and in others it is a 100 per cent demand rate.

Finally, an amendment to the Senate comprehensive energy bill conditions import licenses to deal with anti-competitive impacts on U.S. gas producers, including competitive disparities created by different rate design methodologies.

TransCanada believes that it is critical for Canadian producers, marketers and transporters to work together to dispel the myth created by the IPAA. Their motivation is simple -- the protection of U.S. independent producers from Canadian competition.

Strong arguments against these fallacies, particularly the rate tilt issue, must be brought to the attention of both FERC and the U.S. legislators. I should note that we support the FERC initiative to review the "rate-tilt" issue since, as discussed below, we believe the IPAA argument are without merit.

First of all, end users base their gas supply decisions on the total cost of gas supply and transportation and other factors -- not just the commodity rate. U.S. buyers in the Northeast, for example, have signed contracts with Canadian producers because they have offered terms better than their competitors -- long-term, secure supplies at competitive prices. These so-called "tilts" and "playing fields" haven't won sales for Canadian producers -- offering the best deal has.

Secondly, rate differentials between pipeline systems exist for many reasons besides rate design cost classification including age of the system, distance, load factor, service and physical characteristics of the pipeline. In fairness, rate differentials between all U.S. pipelines would have to be redressed.

Thirdly, the IPAA's argument is not consistent with the spirit of the Free Trade Agreement. The IPAA is singling out Canadian gas.

Fourthly, current regulatory policies in Canada and the U.S. are designed to increase the gas supply options of gas buyers and enhance competition. The IPAA's attempt to get FERC to protect existing suppliers from competition goes against this policy.

Fifthly, several U.S. pipelines have recently proposed changes to their cost classification methodologies to enhance their competitiveness. These pipelines are moving away from the MFV towards FFV. As mentioned earlier, the FERC also began a major shift in its position on the use of the MFV rate design by approving the FFV rate design for 9 Northeast projects.

Lastly, it is significant that IPAA has neglected to bring to FERC's attention that rate designs on certain U.S. pipelines make Canadian gas supplies less competitive with U.S. supplies. The CPA and others have worked hard in the rate cases of companies such as Northern Natural and Northwest Pipeline to redress these inequities.

It is critical that the myths about Canadian Gas's competitiveness being told and accepted in certain quarters be dispelled once and for all.

On the legislative front, in addition to the amendment to condition import licenses to redress any anti-competitive impacts on U.S. suppliers, the Senate Energy Committee has also approved an amendment to the comprehensive energy bill that would shift jurisdiction over gas imports from the DOE to FERC. If successful, this would leave all aspects of import certification to the more time consuming FERC process. Canadian suppliers would face greater regulatory delays and exports would be impeded.

These legislative amendments are potentially very serious given that they specifically target Canadian natural gas. This potential threat to Canadian natural gas exports is a challenge that the Canadian gas industry must face head on. Otherwise the retention of and access to our hard won U.S.markets will erode due to protectionist moves in the U.S.

(2) Transportation Capacity

The impact of deregulating Canadian gas prices in a time of surplus conditions has been depressed prices. In some cases, producers have had no alternative but to sell their gas at prices apparently near replacement cost. With Canada's gas producers facing an uncertain future, exploration and development of new supplies has languished. For some time, it has been clear that the remedy for this situation is the expansion of the existing Canadian gas transmission systems to meet demand in existing and new markets.

The shortage in transportation capacity has also resulted in producers competing to gain access to the limited capacity available. This is the heart of the NOVA receipt point issue that has received much attention lately. Adding receipt capacity gives producers greater flexibility in moving their gas to market on the limited downstream capacity available. This unfortunately has further contributed to depressed prices.

The good news is that the natural gas transmission industry is responding to the need for additional transmission capacity.

In Canada, TransCanada's system deliveries have increased from 1.2 Tcf in 1985/86 to about 1.5 Tcf for the 1989/90 contract year. Deliveries are expected to grow to almost 2 Tcf by 1992/93 given the approval of our 1991 and 1992 Facilities Application a few days ago.

Because TransCanada assumed the risk of ordering pipe and compression prior to receiving the decision, we expect that incremental volumes will begin to flow from Alberta to the Iroquois Gas Transmission system by November of this year. Full volumes are expected to flow by November of 1992. This additional 575 MMcf/d to the U.S. Northeast will go a long way in dissipating the surplus of natural gas in Alberta.

Now that the decision on our last major facilities application has been rendered, TransCanada is in a position to respond to additional requests for transportation service. This slide shows the new requests that I expect will underpin

TransCanada's next application. You will note that over 70% of the service from Western Canada is for the Eastern Canadian market.

A recent American Gas Association report concludes that, in 1990 alone, over 6,000 miles of new pipeline and looping were approved in the U.S. to add 10 Bcf per day of new capacity at a cost of more than $6 billion. An additional 9 Bcf per day is in various stages of planning or regulatory approval. These are huge numbers! The report does state that "not all of the projects will be built, nor are all projects additive for the purpose of determining how much capacity will eventually be available to serve industry and consumer needs". Based on our analysis, we agree that there is a large degree of double counting and that many of these projects will not actually be constructed. For example, most in the industry agree that only one of the California projects to bring Canadian supplies to the region will proceed during the next few years. Consequently, the level of new incremental capacity to market that will ultimately materialize is considerably less than that shown on this table taken from the AGA report. However, it remains the case that the natural gas transmission industry is responding to demands for additional capacity.

The explosion in pipelining activity that will connect new supply basins to new markets and that will debottleneck existing capacity means that there will be much greater flexibility in moving gas to markets than existed historically.

Many pipelines, once monopoly transporters, will face competition to retain their current shippers, to maintain their traditional markets and to gain new markets. Canadian producers will also face added competition from U.S. suppliers in their traditional markets, including Eastern Canada, as it becomes easier to move gas to market.

The challenge for the transportation industry will be not to overbuild capacity into demand regions. TransCanada is sensitive to this concern.

(3) Quality of Service

TransCanada is responding to the challenge of this new competitive environment by focusing on service quality for our shippers. This means that in addition to cost effective and reliable services, TransCanada is working to develop flexible and accessible services.

TransCanada is committed to providing service at the lowest possible cost. From a planning standpoint, facility additions are minimized by designing certain sections of the pipeline on the basis of forecasted load factors and not peak demand. In designing facilities, we determine the most economical way to move incremental volumes of gas through our system -- be it through Northern Ontario or through Great Lakes. This philosophy is also extended to our day to day operations. Utilizing a flow-split equation, Gas Control assures that volumes move through our system along the most economical route.

I must emphasize the important role that shippers play in minimizing costs that they will ultimately bear. We ask shippers to provide their best estimates of seasonal and annual deliveries to ensure that we don't under or over design any facility additions. These delivery estimates also enable us to optimize our day to day operations and maximize capacity that can be made available for IS service.

TransCanada is continually looking for ways to improve the safety and reliability of the system. Since 1987, we have been setting operational targets and measuring performance in relation to these targets. These targets are challenging the development of ideas to reduce pipeline incidents, to provide a safer work environment, to achieve better compressor reliability, to improve work practices and productivity, and to operate the system more efficiently.

In terms of flexibility we are developing in concert with our shippers a portfolio of services that include assignments, diversions, backhauls, and negotiable IS rates.

Firm shippers not able to use their service entitlements can assign all or part of them to other shippers either temporarily or permanently to maximize their load factor on the system. We are attempting to facilitate these assignments by providing a current listing of shippers who may be interested in assigning or accepting service entitlements in our monthly publication -- Shipper News. To help shippers optimize their capacity entitlements, TransCanada also provides shippers with the right to divert volumes upstream and downstream of delivery points. The determination of rates for both backhauls and interruptible service will have important implications for U.S. gas competing in traditional Canadian markets.

With regard to accessible services, TransCanada, being an open access transporter, provides shippers non-discriminatory access to our system. We are also working to enhance communications with our customers to make our system more accessible.

In addition to having our transportation representatives refocus their attentions on our customers needs and wants, we are introducing an electronic bulletin board to provide shippers with on-line access to public information on our system such as tolls, fuel ratio's, our Queue, etc. As well, we have begun publishing a monthly publication called "Shipper News" and are considering a news letter that will highlight events and issues on our system that our shippers should be aware of.

TransCanada firmly believes that providing our customers with the services they require will improve our competitiveness and this will improve our shippers' position in the market!

(4) Gas Supply

The last challenge for the Canadian gas industry that I want to touch upon today is Gas Supply - the mainstay of our industry. For the last couple of years we as an industry have not focussed on it. We have been preoccupied with marketing and the unbundling of pipeline sales and transmission services. The time has now come to address the issue of gas supply and allay some of the fears expressed by some Canadian consumers and governments regarding future supplies and the ultimate potential of Canadian gas supplies.

TransCanada and its shippers have a keen interest in ensuring that natural gas supplies will be available over the long-term to keep the pipelines full.

TransCanada believes that the untapped potential of the Western Canadian Sedimentary Basin is large. Our views are based, in part, on the result of a gas supply model developed by Sproule Associates Limited. This slide illustrates that the deliverability from **conventional** natural gas reserves in the basin can match or exceed expected demand until nearly 2010. In addition, there is great potential for coal seam and unconventional gas supplies. Successful development of coal seam gas in the San Juan Basin has been achieved and recent Canadian studies confirm that similar developments are possible here. Beyond this, Canadian Arctic gas stands ready in the wings to meet any shortfalls in production from the traditional production areas of Western Canada.

Canadian gas generally also has lower finding costs compared to other basins in North America. The ultimate reserve potential and the competitive finding costs of Canadian natural gas will provide the Canadian natural gas industry with a competitive advantage in meeting the needs of consumers and providing North America with a secure long-term supply of energy.

The challenge for the Canadian gas industry is to demonstrate that the workings of the market provide the necessary incentive to explore, produce and transport Canadian gas supplies over the long-term. Canadian governments and consumers must believe in the workings of the market and realize that gas sales, including sales to the U.S., are necessary to generate revenue to find more gas. Actions to artificially restrict gas sales in an attempt to protect gas supplies will be self defeating.

Summary and Concluding Remarks

The new competitive environment faced by all facets of the natural gas industry has brought with it new challenges but also new opportunities. Canadian natural gas now has the ability to compete with U.S. gas and alternative energy sources.

Recent policy developments in Ontario with the moratorium on Nuclear power and in the U.S. with the Clean Air Act and the National Energy Strategy provide real opportunities for natural gas, particularly as a fuel for power generation.

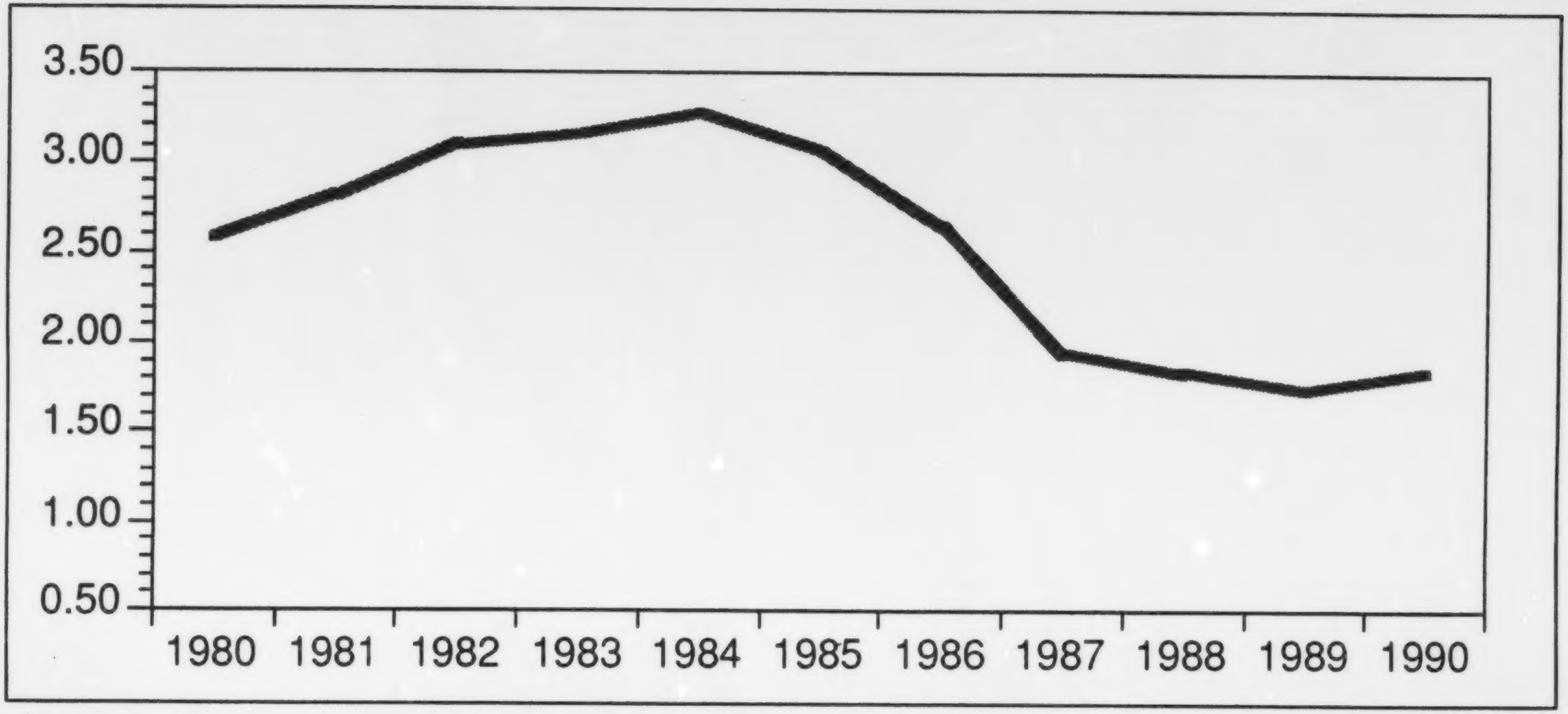
However there exist real challenges in the areas of transportation rates and gas supply. It is important to make sure that the Canadian gas industry is not disadvantaged through protectionist attitudes on both sides of the border.

Working together in partnership, natural gas producers, marketers and transporters can capitalize on the advantages of Canadian natural gas: competitive price, environmental preference and secure long-term supply, to meet the challenges of the new competitive environment.

TransCanada PipeLines

MEETING THE CHALLENGE OF THE NEW COMPETITIVE ENVIRONMENT

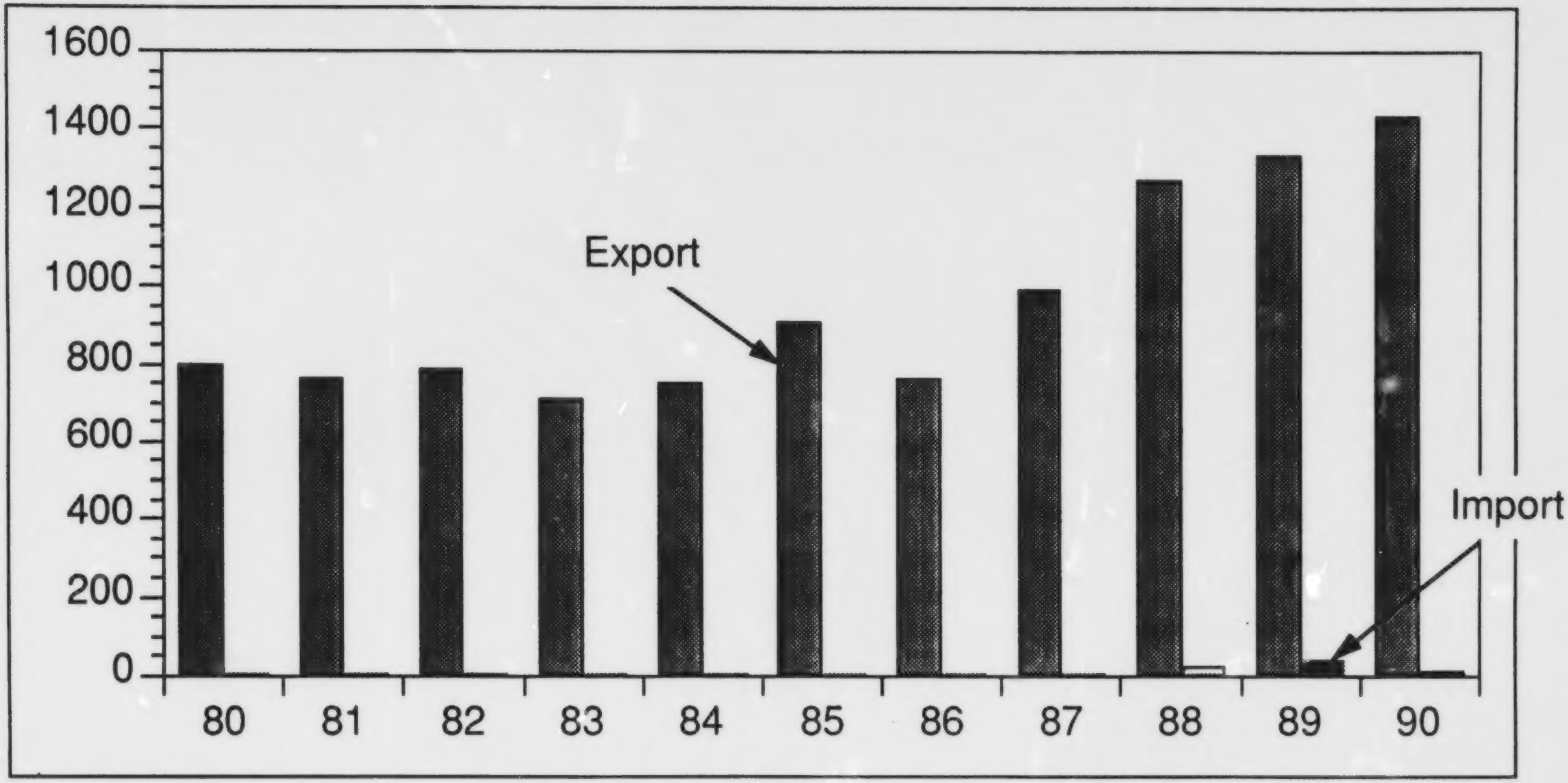
HISTORICAL ALBERTA NATURAL GAS PRICES ($/GJ)*



* WEIGHTED AVERAGE ALBERTA BORDER PRICE

SOURCE: CANADIAN ENERDATA AND EMR

HISTORICAL CANADIAN IMPORT AND EXPORT VOLUMES TO U.S. (BCF/YR)

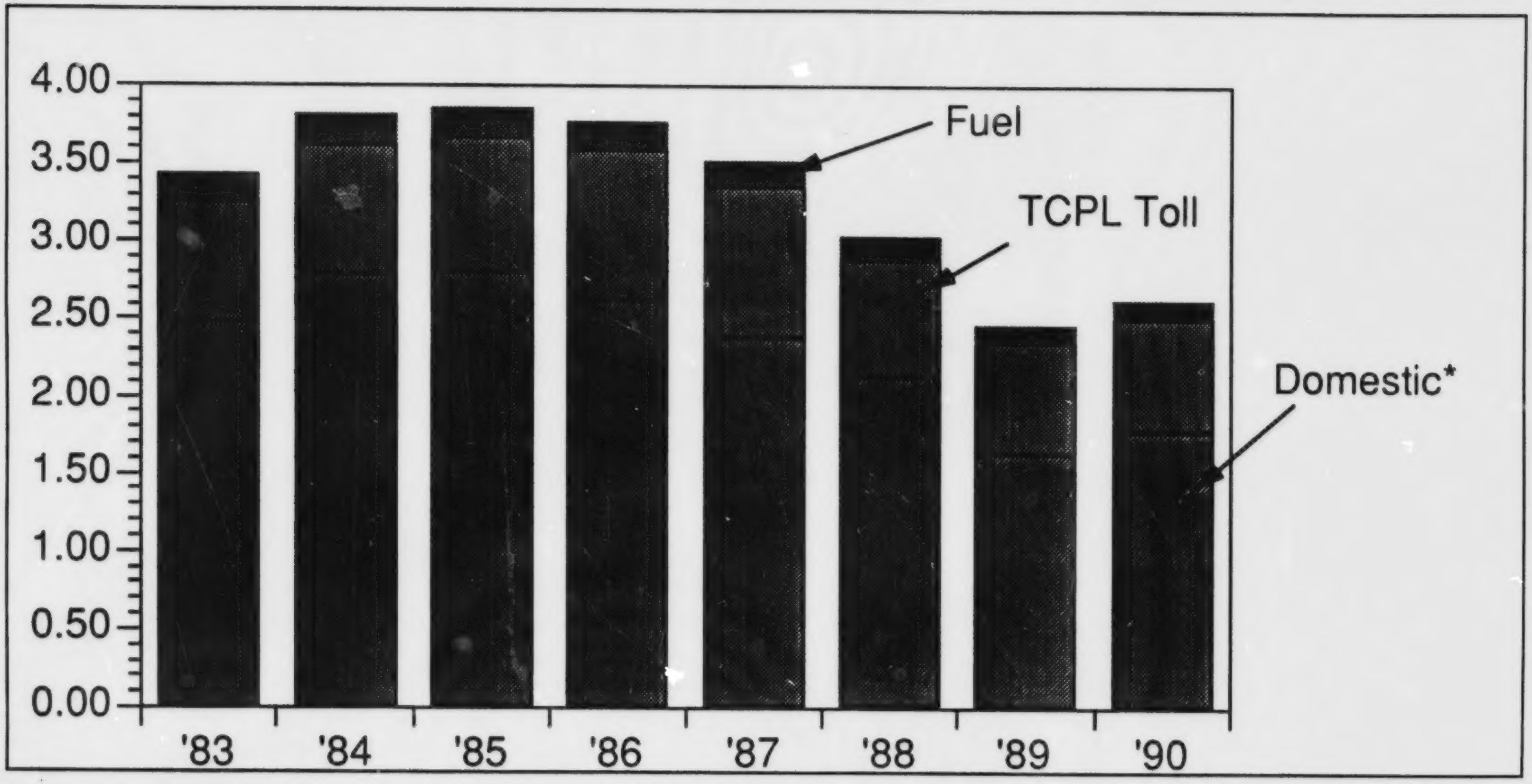


SOURCE: NEB

CHALLENGES OF THE NEW COMPETITIVE ENVIRONMENT

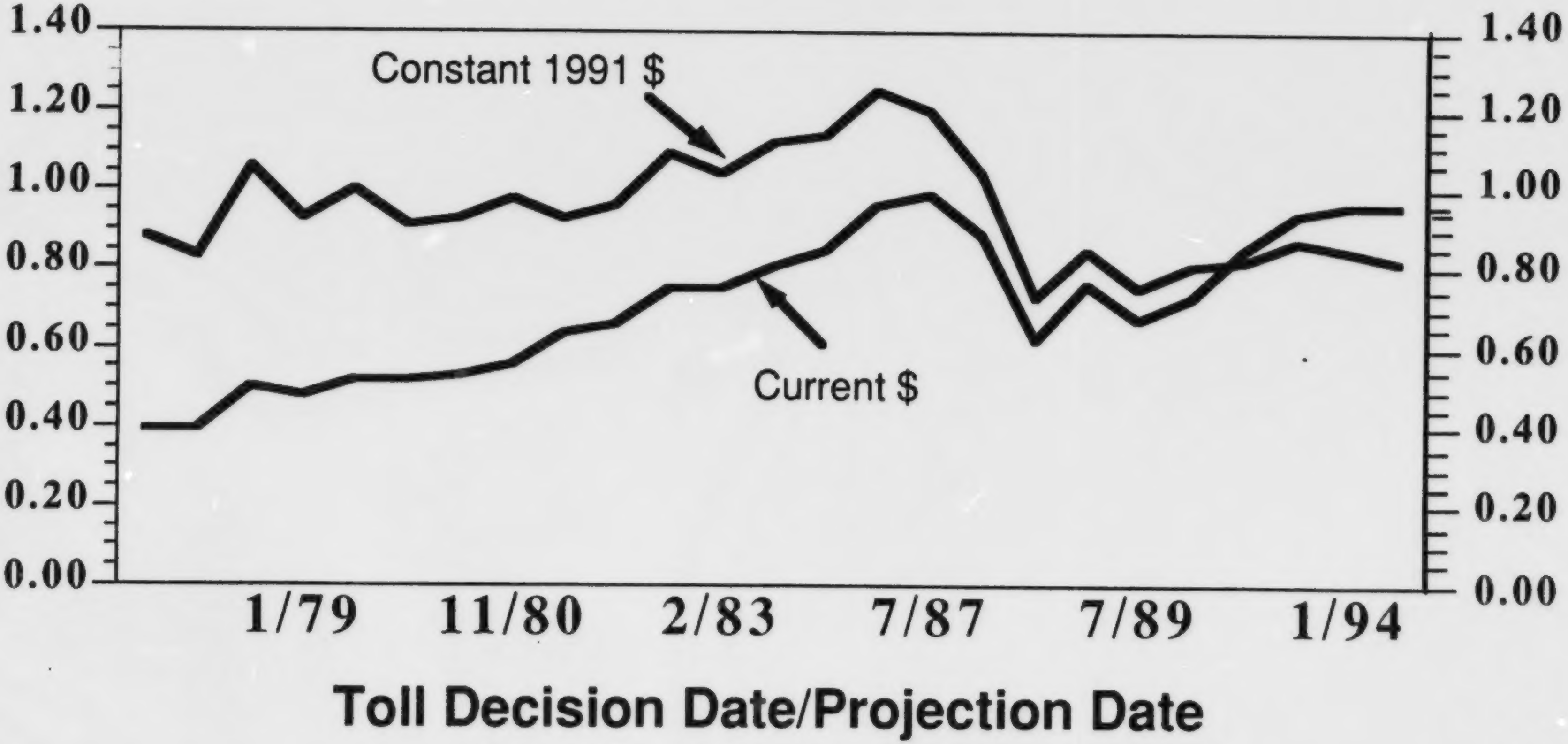
- Regulation
- Transportation Capacity
- Quality of Service
- Gas Supply

DELIVERED PRICE OF NATURAL GAS TO CANADIAN EASTERN ZONE ($/GJ)



* Alberta Border price prior to 1986 is the regulated ABP; subsequently, it is an average domestic price only.

HISTORICAL AND PROJECTED EASTERN ZONE TOLL ($/GJ)



REGULATION

The Challenges:
Rate Design

IPAA'S QUEST:

"A LEVEL PLAYING FIELD"

COUNTER ARGUMENTS TO THE IPAA POSITION

- Supply Decisions Based on Total Costs
- Many Reasons for Pipeline Rate Differentials
- Contravenes the Free Trade Agreement
- Regulatory Policies that Enhance Competition
- Movement Away from the MFV Rate Design - FERC's Approval of FFV for Northeast Projects
- Numerous Regulatory Practices Disadvantage Canadian Supplies

AMENDMENTS TO THE U.S. COMPREHENSIVE ENERGY BILL

- Transfer of Import Authority from DOE to FERC
- Import Licenses Conditioned to "Redress Any Anti-Competitive Impacts on U.S. Natural Gas Producers"

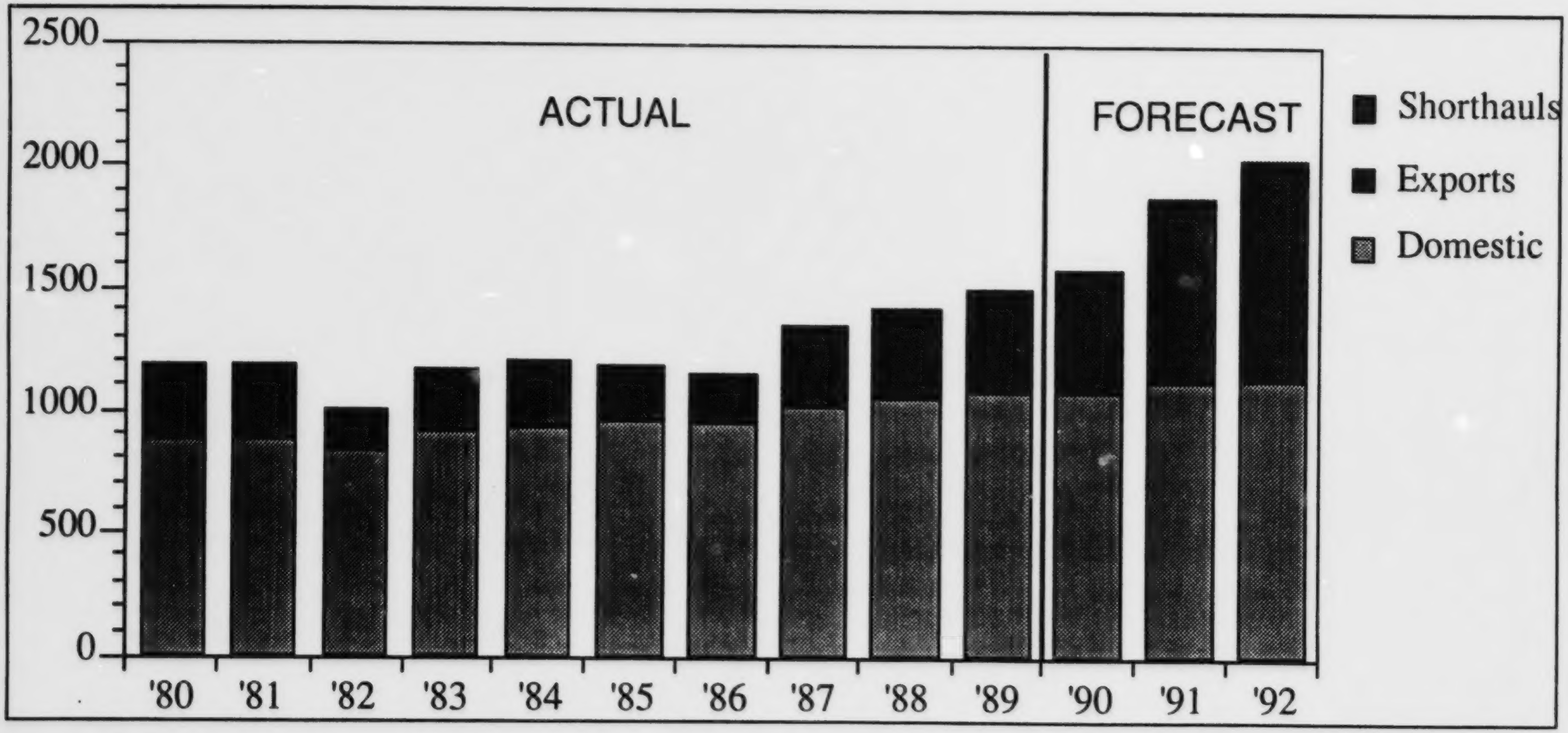
REGULATION

The Challenges:

1) Rate Design

2) Retention/Access to Markets
by Canadian Suppliers

HISTORICAL & PROJECTED DELIVERIES ON TCPL SYSTEM* (BCF)



* Contract year beginning November 1.

EXPANSION UPDATE (GH-5-89)

Date	Demand Region	Incremental Service (MMcfd)	
		FS	STS
Nov 1/91	Domestic	105	35
	Export - West	14	
	Export - East	50	
Jan./92	Export - East	187	
Apr./92	Export - East	176	
Nov./92	Export - East	299	
		831	35

EXPANSION UPDATE (1992/93 FACILITIES APPLICATION)

Date	Demand Region	Incremental Service (MMcfd)	
		Long-Haul	Short-Haul
Nov./92	Domestic	169	39*
	Export - West	5	0
	Export East	61	48
		235	87
* STS			

APPROVED PIPELINE PROJECTS [1] IN THE U.S. IN 1990-91 BY REGION*

Region	$ Millions	Miles	Capacity (MMcfd)
Northeast	1,969	1,410	2,998
California[2]	2,989	3,017	3,243
Arkoma	642	817	2,000
San Juan	242	407	820
South Atlantic	157	190	733
Louisiana/Mississippi	64	65	784
Michigan	40	126	135
TOTAL	6,103	6,032	10,713

[1] Includes pipelines approved pending environmental review and includes pipelines proposed and approved during 1990-91.

[2] Less WyCal project; includes some service to Pacific Northwest.

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* SOURCE: AGA "New Pipeline Construction - Status Report Year-end 1990, January, 1991

TRANSPORTATION CAPACITY

The Challenge:

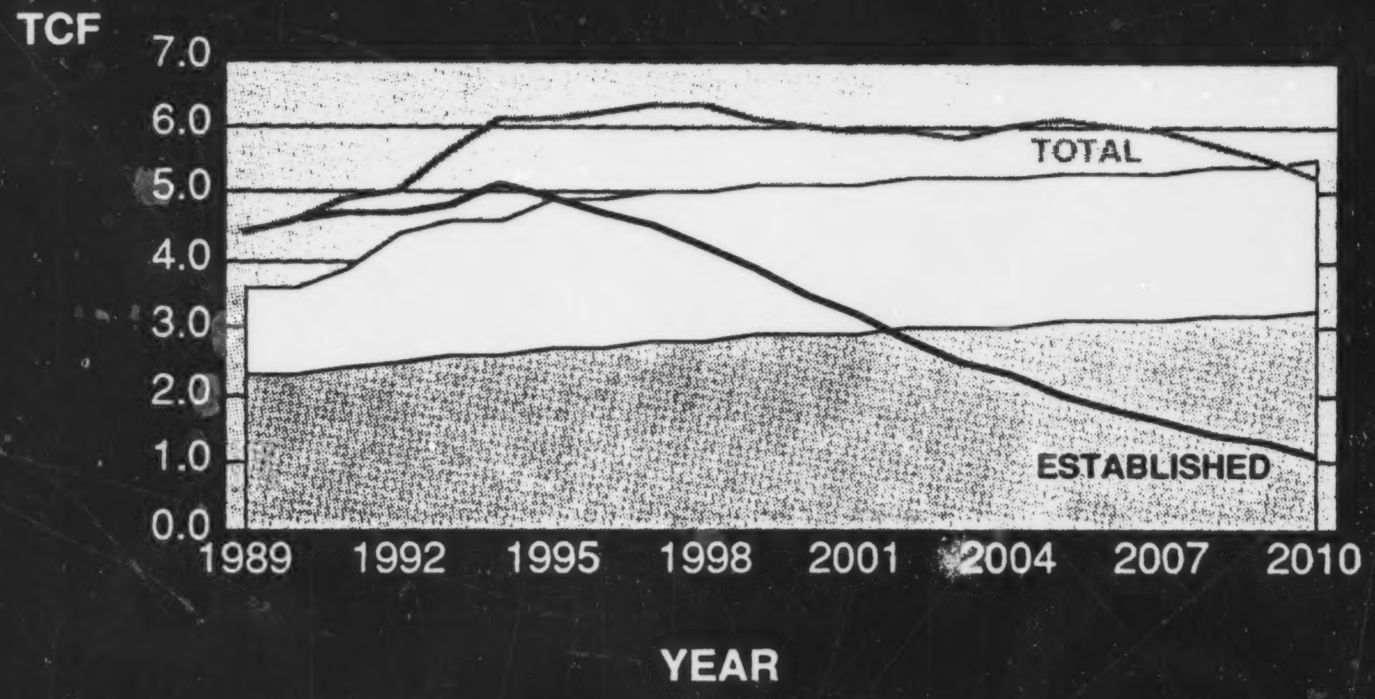
Do Not Overbuild Capacity into Demand Regions

QUALITY OF SERVICE

- The Challenges:
  - Cost-effective Service
  - Reliable Service
  - Flexible Service
  - Accessible Service

WESTERN CANADA SEDIMENTARY BASIN PRODUCTIVE CAPACITY FORECAST FROM "CONVENTIONAL TYPE" RESERVES

240 Tcf (inferred), ROT 1/3500



Source: TCPL Estimate

March, 1991

GAS SUPPLY

The Challenge:

Demonstrate That Gas Supply Will Be Available Over The Long-Term To Support The Exploration, Development And Transportation Sectors Of The Gas Industry

SUMMARY

Working Together in Partnership we will Meet the Challenges of the New Competitive Environment

Capital Recovery and Pricing Issues:

Depreciation and Dismantling & Environmental Restoration

Emerging Issues in the 1990s

Richard N. Hildahl
Timothy R. Crichfield

May 15, 1991

ERNST & YOUNG

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I. Overview

Transportation and Energy Development

During the past decade, the energy industry in North America has faced a number of challenges. The price of oil and gas fluctuated significantly and we found ourselves at the end of the decade, with prices (in real terms) lower than they were in the early 1980's. Sensitivity to the environmental impacts of exploration, development, transportation and processing of petroleum and petroleum products has increased. Recent events in the Middle East have re-emphasized the risks associated with continued reliance on this area for energy supplies.

The messages we in the industry are hearing from the public, as contradictory as they may seem, are:

- We want plentiful and inexpensive energy;
- We want to be secure from disruption of supplies; and
- We do not want adverse environmental impacts.

We find ourselves in North America attempting to operate within the constraints of these often competing objectives, under the watchful eye of the press and regulatory authorities. In addition, there are certain realities that constrain us further:

- Much of the conveniently located energy has been found.
- Significant new finds may lie in areas far removed from population centers, under thousands of feet of water, and/or in sensitive environments.
- The economic viability of the development of heavy crude, oil shale and other non-conventional reserves is sensitive to the delivered costs.
- There is significant burner tip competition between alternative sources of gas and between gas and fuel oil.
- The development of these reserves will be dependent upon the delivered cost relative to alternative supplies from the Middle East, Africa, etc., as well as developed supplies in Canada and the United States.
- The availability and cost of transportation will play a significant role in determining the commercial viability of the development of new reserves in North America.

The ability of pipelines to transport both liquids and gases efficiently and safely is well established. However, the questions of capacity, location, timing, and cost recovery must be addressed for new facilities as well as for expansions of existing pipelines.

The Apportionment of Risks

The owners of pipelines face the risk that demand for their services will not be sufficient both to allow them to recover their investment and costs and earn a compensatory return. There is the risk that failure to anticipate adequately the expenses related to removal of facilitates or mitigation of environmental impacts at the end of a project's useful life will adversely affect life-cycle economics.

The magnitude of these risks is significant, and strategies to apportion risks between project sponsors, lenders, and shippers must be a strategic concern for any pipeline company. Depreciation schedules may be used to adjust the risk profile. The use of throughput base depreciation, deferral of depreciation and other mechanisms have been approved by regulators in the presence of significant risks. In the case of gas pipelines, the use of demand or reservation charges apportions risks among various classes of service.

The increased sensitivity to environmental concerns has led to more stringent requirements for the removal of facilities and restoration of the site subsequent to the cessation of commercial operations. The cost for complying with these requirements can be substantial. If these costs are not recognized in current cost of service, they will become unfunded expenses that will be paid by the pipeline owner.

In many instances, contemporary toll methodology for regulated liquids and gas pipelines does not recognize these future expenses when calculating cost of service. By default the risks for complying with the requirements for removal of facilities and restoring the environment to the standards mandated by law are borne by the pipeline industry.

However there have been instances where regulators have allowed inclusion of negative salvage or "restoration and removal" expense in the cost of service. For liquids pipelines, the treatment (thus far) has been limited to crude oil pipelines in Alaska that are subject to removal provisions in the leases granted for right-of-way. The Federal Energy Regulatory Commission ("FERC") in some cases has allowed the inclusion of negative salvage for regulated gas pipelines when the pipeline could establish that compliance with Department of Transportation regulations for abandonment would likely require expenditures to purge lines and remove above ground facilities. There have been a number of proceedings to set recovery mechanisms and amounts for both onshore and offshore facilities.

In Canada the National Energy Board ("NEB") has yet to establish a policy for inclusion of negative salvage in the cost of service of the gas pipelines in regulates.

Depreciation and Negative Salvage

The depreciation schedule used for calculation of the regulated cost of service can have a substantial impact upon both the risk profile faced by pipeline owners and the prices paid by shippers. In the case of new facilities or where major expansions are contemplated, the ability to respond to market conditions may require depreciation methods other than the conventional straight line, age/life approaches that are commonly applied by regulators. There are several examples that have been applied within the regulatory framework in the United States and Canada.

The concept of negative salvage as a significant future expense has fairly wide recognition in the energy industry. However, the regulatory history relating to negative salvage for pipelines in the United States and Canada is limited, with the notable exception of Alaska and the U. S. gas pipelines discussed below. There are three issues that require attention: (1) valuation of the future expense; (2) determination of the amount to be included in cost of service; and (3) control and accounting for collections/expense.

The following sections discuss the issues of depreciation schedules and treatment of negative salvage for regulated pipelines in North America.

II. Depreciation and Cost of Service

The Utility Model

> *"The prescription of depreciation rates is one of the most far reaching activities of a regulatory commission in its effect of the rates of service which it authorizes."*[1]

The pipeline industry has from time to time presented arguments that the conditions faced by liquids and gas pipelines are fundamentally different from those faced by a local distribution company or electric utility. Certainly both changing market conditions and the impacts of regulation have made these arguments stronger today than a decade ago.

The regulation of utilities is evolving. However, the most widely used method for determining utility depreciation charges continues to be the straight-line method, using average service life, and accounting for salvage value. This is consistent with the regulatory objective of "relating depreciation to consumption with time unless service is tied to a contract period."[2]

Pipelines can face quite a different set of circumstances. There are at least three situations that may warrant consideration of departure from the utility model:

(1) Single purpose projects drawing on a declining resource base;

(2) Start-up or expansion projects facing market entry issues; and

(3) Projects with contractual requirements relating to project financing.

Adoption of straight-line depreciation based upon average life for projects with one or more of these characteristics may unwittingly impose unintended risks of under-recovery on project sponsors.

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[1] Public Utility Depreciation Practices, National Association of Regulatory Utility Commissioners, December 1968, p. 32.

[2] Public Utility Depreciation Practices, p. 101.

Discussion of the Issues

> *"There is in practice, a presumption in favor of the status quo."*[3]

The use of depreciation schedules other than straight-line is not viewed casually by regulators as evidenced by the infrequency that alternative approaches are approved. The arguments advanced by advocates of alternative approaches are frequently stated in terms of economic efficiency. In business terms economic efficiency relates to the following concerns:

- **Willingness to Pay**: Tolls are greater than the market is willing to pay.
- **Life-Cycle Costing**: Recovery of capital does not match the pipeline's obligations to third parties (i.e., debt retirement).
- **Changing Risk Profile**: Where there is uncertainty concerning long term shipments, the risks of under-recovery of capital may be significantly increased by the application of straight-line depreciation relying on the economic life of facilities.

The burden of proof in requesting a non-conventional depreciation schedule is on the pipeline company. Ultimately the questions of depreciation profile and business/financial risks are linked. Pleadings for special treatment in depreciation schedules and high equity returns to compensate for risks may be viewed as disingenuous by regulators. Internally pipeline investors may want to gauge whether the benefits associated with unconventional depreciation schedules warrant adjustments to project hurdle rates.

> *"Departures from the age-life procedures require specific justification such as extraordinary obsolescence or consumption not related to age."*[4]

Implicit in any pleading for use of a depreciation schedules other than straight-line is the contention that the pipeline faces different risks than a utility. These may arise from:

(1) The nature or degree of competition the pipeline faces;

(2) The higher degree of uncertainty concerning the long term requirement for transportation service; and

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[3] Department of Energy, **Inside F.E.R.C.**, McGraw Hill, Inc., January 28, 1991.

[4] Public Utility Depreciation Practices, p. 87.

(3) The cash requirements for debt service being driven by factors other than the useful life of the assets.

These are discussed further below.

Accelerated Depreciation-The Single Purpose Project

The frontier pipelines constructed in Alaska are notable examples of single purpose projects drawing upon a declining resource base. The Trans Alaska Pipeline System ("TAPS") faced and faces uncertainty concerning economic life. Initially when the investments in production infrastructure and pipeline facilities were undertaken, there was considerable uncertainty related to both the long term performance of the Prudhoe Bay[5] reservoir and the pipeline itself. At the time, there were limited data concerning the long term performance of production equipment and pipelines under the stresses of the Arctic environment.

The issue of the rate charged for transportation by TAPS was of considerable interest to the State of Alaska ("State").[6] The State's proceeds from royalty interest and production tax are calculated on a netback basis, which deducts tariff expense and other transportation and sales expense from sale price. The initial TAPS tariffs were filed in 1977 by the TAPS owners ("Owners")[7] under the Consent Decree method. The State protested the tariffs and they were suspended. A complex rate litigation proceeding resulted in a settlement between the State and the Owners that was approved by FERC in June 1985.

The TAPS Settlement Methodology ("Settlement")[8] front-loads depreciation through the use of a "factored" unit of throughput ("UOT") approach. This approach was based upon the estimated producible reserves with weight factors applied to each year's estimates. The weight factor was 1 for the early years declining by an increment of 0.05 per year down to 0.05 by the mid-1990's. Each year's depreciation factor is determined by dividing the product of the "factor" and estimated production by the sum of factors and production for the current year and subsequent years through 2011. To mitigate the problem of declining rate base an incentive after-tax real fee of $0.35 per barrel (in 1983 dollars) was allowed beginning in 1990.

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[5] The Prudhoe Bay field, discovered in 1968, was the basis for undertaking the development of the Alaskan North Slope. A number of other commercially viable fields have been developed subsequently, most notably the Kuparuk River field, Endicott, Milne Point, and Lisburne.

[6] The State has a royalty interest in production of approximately 12.5 percent. In addition, a severance tax of approximately 15 percent is levied on the producers' equity production.

[7] TAPS owners include ARCO Pipe Line Company, BP Pipelines Inc., Exxon Pipeline Company, Mobil Alaska Pipeline Company, and Union Alaska Pipeline Company.

[8] TAPS Settlement Agreement, Parties in Trans Alaska Pipeline System, June 28, 1985, Docket No. OR78-1.

The recent Order by the Commission[9] in the Kuparuk Transportation Company ("KTC") case incorporated UOT depreciation relying on a production profile stipulated by the State of Alaska and the producers. The issue of fees to mitigate declining rate base problems were not raised in this proceeding. By these actions FERC is recognizing the risk of under-recovery faced by pipelines relying on a single reservoir.

The application of UOT approaches to gas transmission pipelines is complicated by peak demand concerns. The generally seasonal nature of gas demand in North America makes peak demand a central concern for cost allocation. Typically the requirements for peak capacity are a key determinant of system sizing and cost. This means the rate design for gas transmission must not only concern itself with the number of units transported but also the peaking patterns of demand. Typically a shipper receiving firm transportation with wide variations in demand (i.e., low load factor) will be assessed charges based upon peaking characteristics (D1) as well as total units transported (D2 and commodity charge). That will result in the average expense per unit shipped being higher than for a shipper with a more consistent demand (i.e., higher load factor). Opponents to UOT depreciation for application to gas transmissions lines have focused on the failure to account for the peaking characteristics of demand.[10]

The regulation for gas pipelines has long recognized the reserve limitations as a basis for limiting depreciable life. In the recent FERC proceedings relating to three projects[11] to serve the Kern River EOR market, each was granted a 25 year depreciation life based upon the estimated life of reserves.

Adjusting Depreciation for Market Conditions

A persistent industry criticism of original cost rate making, when combined with straight-line depreciation, has been the front-end load problem. Under the original cost approach, which applies a nominal weighted average return to an original cost rate base, the result is a higher allowed return in the early years of operation, declining as rate base is depreciated. This approach can present problems when a new pipeline with a non-depreciated rate base is entering a market in which it will be competing with older facilities, or where there is transportation price sensitivity. The problem is exacerbated when initial volumes are low, such that there are fewer units over which to spread costs.

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[9] Kuparuk Transportation Company, April 25, 1991, FERC Paragraph 61,122, Docket Nos. IS85-9-000, OR85-1-000, and OR90-1-000.

[10] National Energy Board Reasons for Decision, Westcoast Transmission Company Limited, April 1985.

[11] The projects are Kern River, Wycal, and Mojave.

A variety of solutions have been approved by regulators to address this issue. In the case of Cochin Pipe Lines Limited ("Cochin"),[12] deferral of depreciation and flow through of tax allowances were used to mitigate the front-end load problem by reducing collections for depreciation and taxes on return on equity during the early years of operation. The rate design for Cochin was shaped to balance the requirements of contract shippers and the pipeline. Shippers were concerned that a conventional rate design would yield tolls that would imperil the development of the reserves that the pipeline served. The pipeline owners were willing to accept increased levels of risk associated with deferral of capital recovery for the opportunity to earn a compensatory return should the development of reserves exceed expectations.

There are a number of recent instances where non-conventional depreciation schedules have been allowed by regulators in response to market conditions. The rate design for the Kern River Pipeline (i.e., gas pipeline serving Kern River EOR) includes limitations[13] on depreciation during the first 15 years of operation[14] and deferral of collection of return on equity during this period. This allows Kern River to offer long term levelized rates demanded by the market. The settlement approved by FERC for Northern Border Pipeline Co. includes an "increasing rate depreciation" method which defers the recovery of depreciation to the latter half of the company's life.[15] The rate design for the Iroquois project, proposed to provide a connection with TransCanada PipeLines and markets in the Northeastern United States, includes deferral of depreciation and return on investment during the first year of operation.[16]

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[12] The Cochin methodology was designed to match the life-cycle characteristics anticipated for the pipeline system. Delayed depreciation charges and flow-through income tax allowances are used to prevent potential problems associated with the front-end loading phenomenon and to provide project life revenues acceptable both to owners of the pipeline and to contract shippers.

[13] During the first 15 years only debt service (70 percent debt capital structure) is included in depreciation. The remaining capital investment and return on equity are primarily recovered in years 15 through 25.

[14] In recognition of demand considerations in the marketplace, the Commission will permit Kern River to utilize a levelized cost of service for a period of 15 years, as was authorized in WyCal.

[15] "FERC Approves Northern Border Settlement Offer Providing for Substantial Cost of Service Reductions in Next Few Years due to Further Deferral of Depreciation Cost Recovery," **Foster Natural Gas Report**, August 2,1990, p. 3.

Matching Depreciation With Debt Service

The use of non-recourse or limited recourse project financing is another mechanism for apportioning risks. The execution of carriage agreements by shippers, and the subsequent use of these to secure high levels of debt financing (i.e., 70-75 percent) effectively lowers financial risks and shifts risks from the pipeline company to the shippers. The shippers benefit in turn by the higher leverage and lower debt costs that their guarantees enable.

The use of project financing secured by shipper commitments may warrant consideration of depreciation schedules that account for the term of the project financing. In today's markets, non-recourse or limited recourse project financing typically has terms less than the theoretical service life of assets (i.e., 15-18 years). The shorter retirement schedule, coupled with the heavy reliance on debt (i.e., 70-75 percent), will increase the financial risk for equity holders if age based, straight-line methods are relied on.

The FERC-approved rates for Kern River "will enable Kern River to recover all of its debt service during the first 15 years." Kern River's rates include several allocation innovations to accommodate both the requirements of project financing and the front load problem discussed previously. The overall depreciation period is 25 years, well short of the engineering life of assets. As noted, debt is recovered in the first 15 years, with the remaining capital recovered in the 15-25 year period. Beyond 25 years a management fee is allowed (see discussion of TAPS Settlement Methodology above) capped at 10 percent of the average pre-tax return for the prior period.[17]

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[16] Inside F.E.R.C., McGraw-Hill, Inc., February 11, 1991.

[17] Federal Energy Regulatory Commission, Paragraph 61,069, p. 61,150.

III. Negative Salvage

Overview

The question of "walkaway" costs has been emerging as a significant issue for both the financial accounting and the regulatory community over the past two decades. The societal costs of allowing owners of facilities that can produce hazardous waste to walk away from facilities at the end of their economic life and leave the cost of remediation to society are significant. In response to past abuses, an emerging body of law has placed increasingly stringent requirements upon owners to pay the cost of remediation. The energy industry has recognized that contingent liabilities (i.e., negative salvage) potentially faced at the end of a project's life can have a material impact on financial results and are evaluating appropriate adjustments in both project appraisal and financial accounting to reflect their exposure. Recently Chevron, ARCO, Texaco, and Sun have taken significant write-downs against earnings for future environmental expense.[18]

Much of the material transported by liquids pipelines, or the residues/byproducts of handling and storage are classified by regulators as hazardous materials. The same is true for some of the residues that may remain in gas transmission facilities.[19] Remediation will be the responsibility of the owner. It is prudent for the owners of gas and liquids pipelines to evaluate their exposure and develop strategies and procedures to ensure that financial and regulatory accounting properly reflect potential liability. More importantly, the calculation of cost of service should include an allowance for funding this future expense.

In the United States there is a long history of regulatory proceedings before the FPC and its successor FERC relating to the collection of decommissioning costs for nuclear utilities. There is limited experience in the case of liquids pipeline in Alaska where the terms of right-of-way leases[20] require the removal of facilities and the restoration of the land at cessation of commercial operations. The United States Department of Transportation has requirements relating to abandonment of gas pipelines.[21] On at least three occasions, FERC has allowed the inclusion of negative salvage in gas pipelines' cost of service.[22]

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[18] "Environment Key to Big Write Downs", **Oil & Gas Journal**, February 5, 1990, p. 23.

[19] Texas Eastern was reported in the January 28, 1991 issue of **"Business Week"** to face potential costs of $730 million relating to cleanup of PCBs spilled along the right of way.

[20] "[u]pon revocation or termination of the authorization of which these Stipulations are part, the COMPANY shall remove all improvements and equipment from STATE LANDS, unless otherwise approved in writing by the COMMISSIONER OR HIS DESIGNEE..." from Exhibit KTC12-1, FERC Docket Nos. IS85-9-000 and OR85-1-000.

There are similar obligations for the removal of pipeline under Canadian pipeline regulations. In 1984, Westcoast Transmission Company Limited asked for inclusion of negative salvage in its tolls to account for these future costs. The matter remains unresolved to date.

There is a fundamental question for a regulated company requesting inclusion of an allowance for a contingent liability of "whether a contingent expense such as this, i.e., one that may never be incurred, is properly included in a regulated entity's cost of service[?]"[23] There are at least two sub-questions: (1) Can the amount of likely expense be determined? and (2) Is there reasonable certainty that the expense will be incurred?

The Prudent Course for a Regulated Entity

The determination of potential liability related to cessation of operations should be part of every pipeline's strategic planning. This requires a concerted effort involving legal, environmental compliance, engineering, and accounting staffs. Once it has been established that a potential exposure exists, the regulatory issues outlined above need to be addressed. If it is determined that the amount of liability is calculable and there is a reasonable certainty of the expense being incurred, the issue of accounting treatment and inclusion for cost of service should be addressed.

- **Valuation of the Expense**: The development of the initial estimate[24] of the expense typically relies on facility-specific, engineering, cost estimation procedures. The assumptions relied upon are clearly defined and alternatives may be considered where appropriate. Typically manpower and equipment requirements, disposal procedures, and permitting requirements are described and a work plan and schedule developed. Standard cost data from current estimating manuals are relied on for determining costs in current dollars.

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[21] CFR 49 Section 192.720.

[22] Columbia Gulf Transmission Company, Docket Nos. RP75-105 and RP76-94. Tennessee Gas Pipeline Company Docket Nos.80-97-000,RP81-54-000, RP81-56-000, RP82-12-000, and RP82-10-000. Pacific Gas Transmission Company, Docket Nos. RP87-62000.

[23] FERC Staff "Initial Brief," Docket No. IS87-36-000, p. 49.

[24] This discussion is limited to expenses related to the removal of facilities, wastes, residues, contaminants etc., and restoration of the physical environment.

- **Accounting Measurement**: In the case of the gas pipelines in the United States, the system average amount granted in cost of service has been in the range of 0.15-0.25 percent of overall original cost overall.[25] The determination will vary from facility to facility depending upon individual circumstances, but discussions with FERC Staff indicated that the 0.15-0.25 percent range is a representative one. This is in sharp contract to Alaska, where the results of detailed studies of the removal and restoration ("R&R") costs for liquids pipelines have yielded estimates (current dollars) of more than ten percent of the "as built" cost.

  In the case of Alaskan oil pipelines the current conventions for the recognition of R&R expenses for financial reporting purposes are:

  (1) The liability is adjusted annually to reflect the effect of monetary inflation;[26]

  (2) The amount remaining to be collected is calculated by subtracting the reserve balance from the revised estimate;

  (3) The current year's expense is calculated by dividing the amount remaining by remaining life, or alternately remaining throughput; and

  (4) A debit is recorded to R&R expense and a credit to R&R reserve.

- **Determination of Cost of Service Amount**: The sinking fund approach has been accepted by FERC for both the nuclear utility industry[27] and liquids pipelines.[28] This approach treats collection as if the after tax collections were deposited in an interest earning fund. Collections are set to provide a balance sufficient to fund the anticipated expenses related to decommissioning at the end of the project's economic life.

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[25] For PGT the rates for class of asset varied from 0.45 percent for production plant and gathering, 0.23 percent for original assets, and 0.105 percent for expansion assets.

[26] In some cases the engineering estimate may be periodically updated.

[27] There are specific provisions in the IRS code and the regulations of the Nuclear Regulatory Commission that specify the tax treatment and administration of decommissioning funds. These provisions do not currently apply to oil and gas pipelines.

[28] The TAPS Settlement Methodology includes a DR&R allowance calculated using the sinking fund approach.

The recent order by the FERC in the KTC case specified a different approach for funding R&R expenses. The "accrual method"[29] collects the full amount of the estimated expense over the life of the facility. Each year's collections are based upon the remaining balance to be collected divided by some measure of the remaining life of the facility. In the case of KTC, a UOT measure of remaining life was applied.[30] The Commission requires that collections be treated as a credit to rate base. This treatment is comparable to the "negative salvage" allowances for gas pipelines.

In Canada,the NEB first dealt with the issue of "negative salvage" in their April 1985 decision relating to Westcoast Transmission Company Limited. The NEB disallowed Westcoast's request, citing "complexity of the subject."[31] The NEB subsequently conducted a study of the issue, but has not (to date) set a formal policy. Westcoast, in its most recent depreciation study[32] has suggested that NEB hold formal hearings addressing the negative salvage issue.

- **Control of Collections**: The nuclear utility industry in the United States is required to place decommissioning funds collected from ratepayers in an external escrow account. To date, there have been no such requirements by FERC for either oil or gas pipelines collecting R&R allowances in cost of service either to segregate funds or place them in external funds.

  The FERC is considering changing the accounting standards relating to decommissioning costs for the nuclear utility industry.[33] Among the alternatives under consideration is treating decommissioning cost as an "offsetting liability" in one lump sum. There is potential for any new standard being applied to the pipeline industry. To date no final ruling has been forthcoming.

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[29] Kuparuk Transportation Company, April 25, 1991, FERC Paragraph 61,222, Docket Nos. IS85-9-000, OR85-1-000, and OR90-1-000.

[30] The UOT schedule was stipulated by the parties to the proceeding.

[31] National Energy Board Reasons for Decision, Westcoast Transmission Company Limited, April 1985, p. 20.

[32] From discussions with Westcoast Staff.

[33] "FERC Mulling Rule Change to Make Decommissioning Expenses Clearer," Nucleonics Week, May 8, 1989, p. 10.

Some Factors to Consider

The one constant in the equation is who pays for negative salvage when the expense is incurred in the pipeline company. Clearly, prudency dictates that pipelines recognize the potential liability as soon as it can be reliably identified. However, developing an equitable basis for charging shippers is the key to allocation of the risks between shipper and pipeline owner to avoid large, unfunded liabilities at the end of operations.

However, owners must realize at the outset that pursuing contingent claims such as R&R before regulatory bodies has implicit risks, and that pursuing rational economic goals does not ensure rational regulatory outcomes. Shippers and other interested parties naturally prefer not to pay charges and may intervene. Regulators will be concerned that the shipper is shielded for "speculative" expenses.

In balancing the economic goals of the pipeline to fund a future expense against the concerns relating to uncertainty of when the expense will be paid and its magnitude, regulators have imposed solutions which can increase pipelines' financial risks, particularly in the later stages of operation. The credit to rate base approach, favored by FERC[34] for oil and gas pipelines can present problems for a single asset company that will not be continually renewing resources or expanding facilities. As collections are made and credited against rate base, they accelerate the decline of rate base with time. Since there is no offsetting asset in the rate base, the rate base balance can become negative.

For single asset pipelines there is the potential that the pipeline could be in the position of crediting cost of service with the "return" on the collections for remediation of environmental impacts to the extent that the pipeline would earn a very low return. Under the credit approach, the higher the potential cost of remediation (and the related collections for shippers) the greater the financial risks to the pipeline company that it will be denied its regulatory return on investment. This imposes additional financial risk on the pipeline and could make it difficult for the company to attract capital, since the ever increasing credit to rate base from negative salvage adjustments to rate base will erode returns to the pipeline owners.

In recent cases before FERC dealing with the determination of collection amounts for the removal and restoration expenses for Alaskan pipelines,[35] the pipeline companies advocated the sinking fund approach for funding R&R expenses. While there were small differences in the two proposals reflecting unique facts and circumstances, the following generic characteristics are identical:

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[34] Kuparuk Transportation Company, April 25, 1991, FERC Paragraph 61,122, Docket Nos. IS85-9-000, OR85-1-000, and OR90-1-000.

[35] Kuparuk Transportation Company (Docket Nos. IS85-9-000, OR85-1-000, and OR90-1-000) and Endicott Pipeline Company (Docket No. IS87-36-000).

- **Funding Mechanism**: An annuity earning interest on collections and recognizing tax impacts.
- **Target Amount**: Current dollar expense estimate adjusted for anticipated inflation to time of expenditure and reduced by the estimated tax benefits available at the time of expenditure.
- **Earnings Rate**: Collections earn an imputed rate of interest equal to the risk free rate.
- **Tax Effects**: Collections are taxable income when received. The tax shield from expenditures will be limited by the carry-back of losses provision of the current tax law. Imputed interest earnings are taxable income.
- **Collection Schedule**: Unit of throughput collection schedule based upon stipulated throughput profile.
- **Fund Administration**: Funds retained by pipeline company. Periodic "true-ups" to revisit target amount and fund balance issues and revise collections as necessary.

There are three considerations that support the industry's recommendation:

(1) **Risk**: The pipeline company is clearly the party at risk. The cost of remediation will be borne by the pipeline company, not shippers. If the cost exceeds estimates then the pipeline company will make up the difference.

(2) **Benefits**: The future liability arises from the facilities and activities undertaken for the benefit of the shipper. The shipper should be charged for the service of removal of facilities and remediation of environmental impacts.

(3) **Time Value of Money**: Clearly the collection of a negative salvage is a prepayment of an expense. Recognition of the time value of money is required to compensate the shipper for prepayment. However, this is a riskless investment which shields the shipper from any claims related to remediation.

The expressed preference of FERC in the KTC proceeding for crediting the rate base for negative salvage/remediation collections ignores the facts and circumstances facing the pipeline industry, particularly single purpose pipelines. The credit approach effectively allows the shipper to earn the pipeline's cost of capital, which reflects the business and financial risks faced by the pipeline. Yet the shipper faces none of these risks and is shielded from any issues related to future requirements for removal of facilities and remediation of any environmental impacts as imposed by law. The apparent perception that there is an incentive on the part of pipelines to overstate the costs relating to removal of facilities ignores the income and balance sheet effects of the liability created. "Though a pipeline company may not purposely overestimate its retirement costs while setting a rate for the negative salvage element, it certainly benefits if the costs have been overstated."[36] Further, there is ample opportunity to revisit the issue periodically and adjust collections to reflect new information.

In Canada, the NEB has yet to develop a policy. Certainly, producers will not be enthusiastic concerning additional transportation expenses. However, the direction for environmental policy is clear in mandating the remediation of environmental impacts of energy production and transportation. The costs of these efforts need to be addressed now to ensure that investment decisions are based upon realistic assessment of the life cycle environmental expenses. For existing facilities the current tolls should reflect these future expense. Further delays will only complicate the development of an equitable approach for inclusion of these expenses in tolls.

The resolution of negative salvage/removal and restoration issues will have major impacts on the energy business. These costs of complying with environmental requirements related to cessation of operation are significant and are not going to go away. The current regulatory treatments for regulated pipelines are flawed and place disproportionate risks on the pipeline company. The industry needs to consider the most efficacious approach for encouraging the development of equitable regulatory procedures for valuation and funding of liabilities.

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[36] Columbia Gulf Transmission Company, February 7, 1980, FERC Paragraph 63,030, Docket Nos. RP75-105 and R76-94.

IV. Summary and Conclusions

The energy transportation industry in North America will face significant challenges in the next ten years. The efficient utilization of domestic gas and oil reserves in frontier and offshore areas will require construction of significant additions to the transportation infrastructure. These additions will occur only if a flexible, market driven regulatory environment is in place. There are significant cost allocation issues facing the industry in both the United States and Canada. With regards to depreciation, the willingness of regulators to accept alternatives to straight-line "utility" depreciation, where market conditions warrant them, will help facilitate orderly development of new facilities and expansions. This is a particular concern to the high risk frontier developments that are transportation sensitive.

Recognition of the negative salvage exposure of the energy transportation industry is long overdue. The increased sensitivity of the public and the stringent requirements for remediation of environmental impacts will lead to significant future remediation costs when facilities have reached the end of their economic life. The development of an equitable approach to funding these requirements should be a strategic objective for the industry during this decade.

CAPITAL RECOVERY AND PRICING ISSUES:
DEPRECIATION AND DISMANTLING & ENVIRONMENTAL RESTORATION

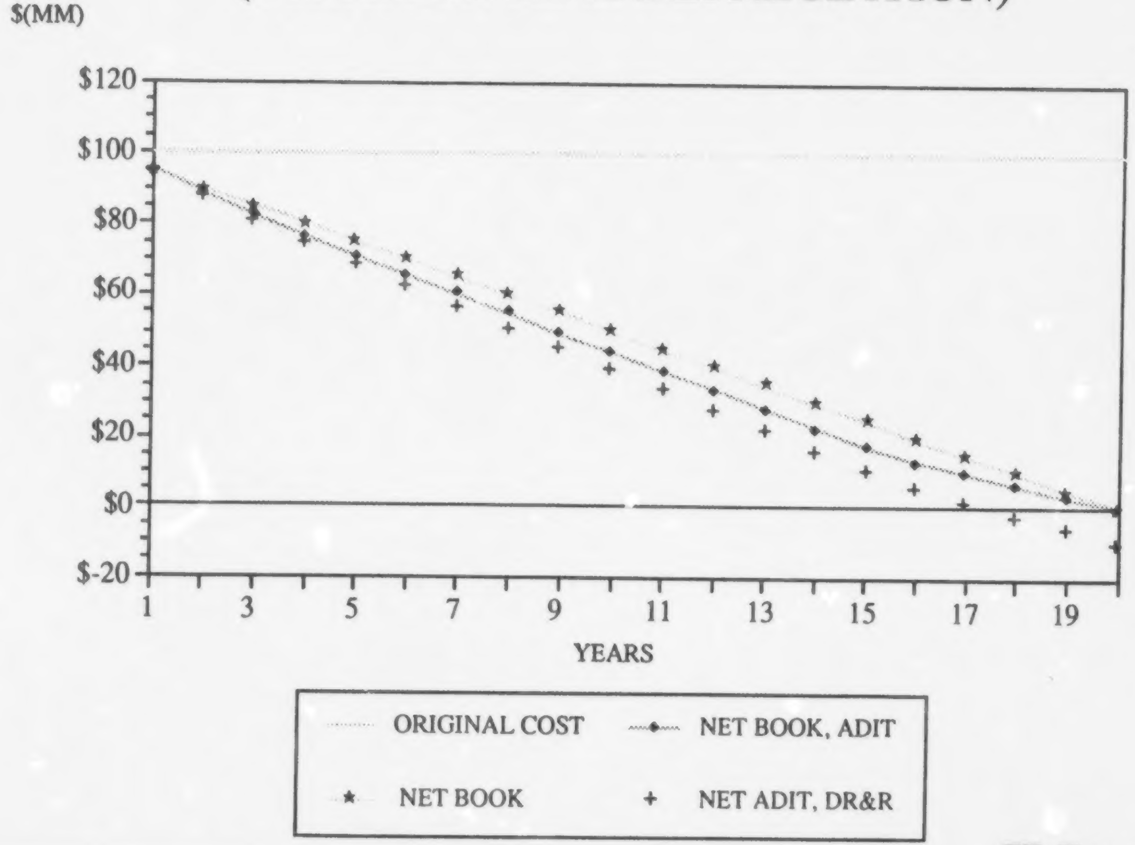
EMERGING ISSUES IN THE 1990'S

Presented by: Richard N. Hildahl
and Timothy R. Crichfield of
Ernst & Young's
Energy and Transportation Group

Canadian Petroleum Association
Pipeline Conference
Calgary, Alberta
May 15, 1991

ERNST & YOUNG

THE PROBLEM OF RATE BASE CALCULATION FOR ENVIRONMENTAL RESTORATION
(STRAIGHT LINE DEPRECIATION)



ERNST & YOUNG

KUPARUK TRANSPORTATION COMPANY
DR&R FUNDING

- KTC should be permitted to include in its rates a charge for DR&R
- Collections should be based upon a stipulated unit of throughput schedule
- Amounts collected should be subtracted from rate base
- Control of funds should remain with the pipeline company

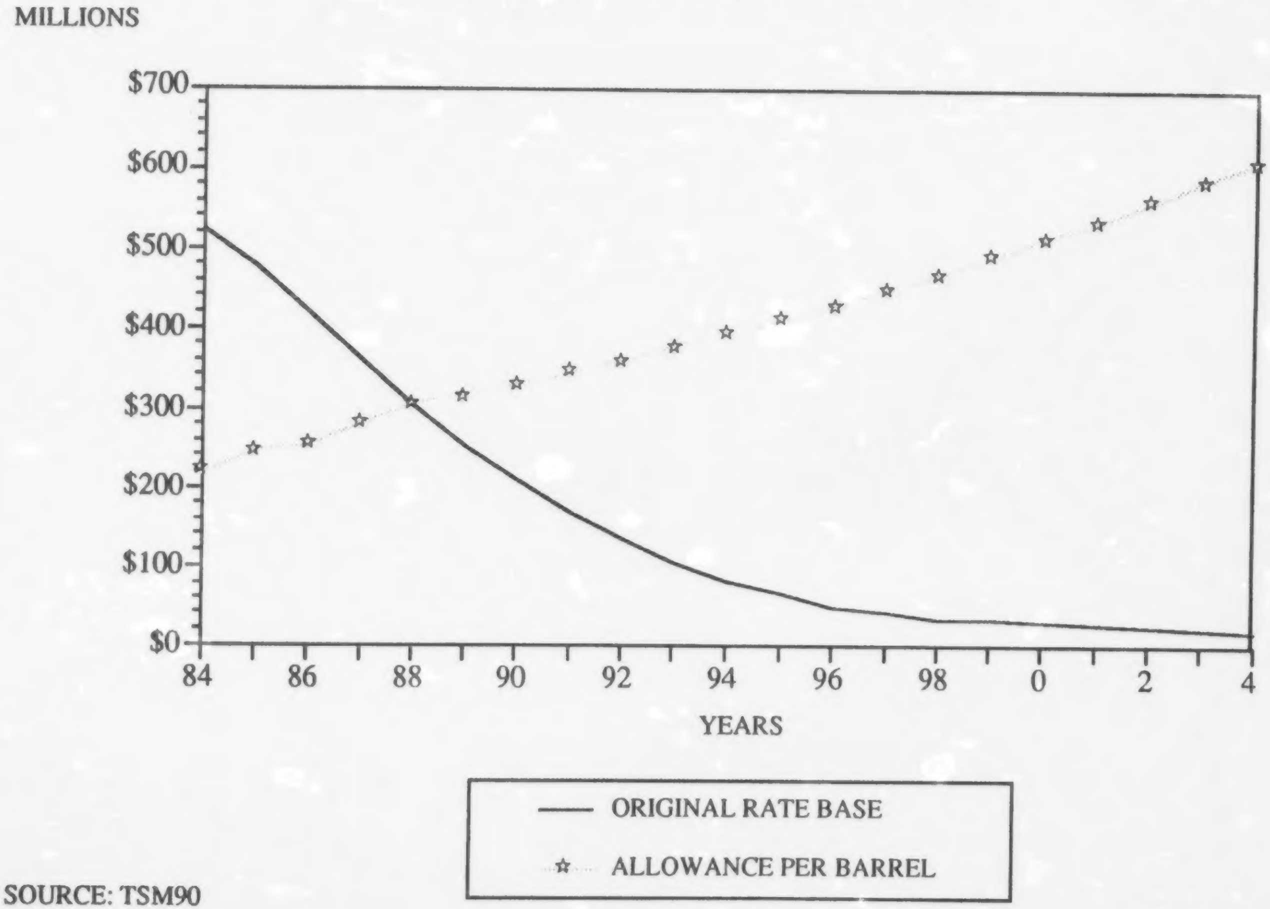
TAPS SETTLEMENT METHODOLOGY

- TAPS carriers should be permitted to include a charge for DR&R in their rates
- Collections should be based upon a stipulated unit of throughput schedule
- Collection amount based upon annuity approach:
    - Collections assumed taxable
    - Imputed interest (taxable) at Moody's A bond rate
    - Full recognition of tax benefits at time of expenditure
    - Expense estimate inflated to time of expenditure
- No reduction of rate base for collections

FEATURES OF TSM

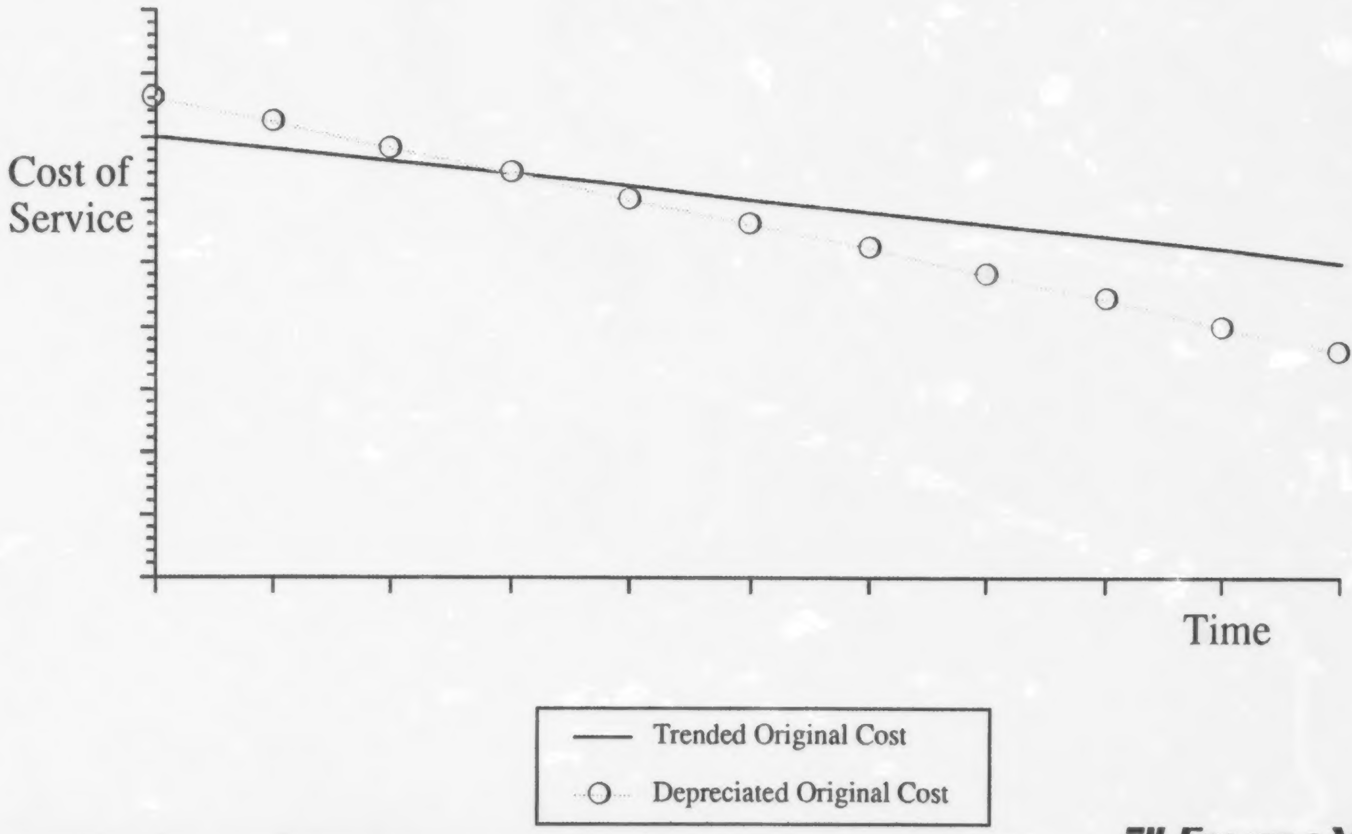
- TOC
- FACTORED UOT
- DR&R
- 100% EQUITY
- INCENTIVE AMOUNT

TAPS SETTLEMENT METHODOLOGY (TSM)
RETURN ALLOWANCE



SOURCE: TSM90

COMPARISON OF COST OF SERVICE LEVELS UNDER DOC AND TOC



ERNST & YOUNG

FERC'S COST OF SERVICE FORMULA

Opinion No. 154-B (351, 351-A) Rate Base

x Weighted Cost of Capital

= Total Return

+ Income Taxes

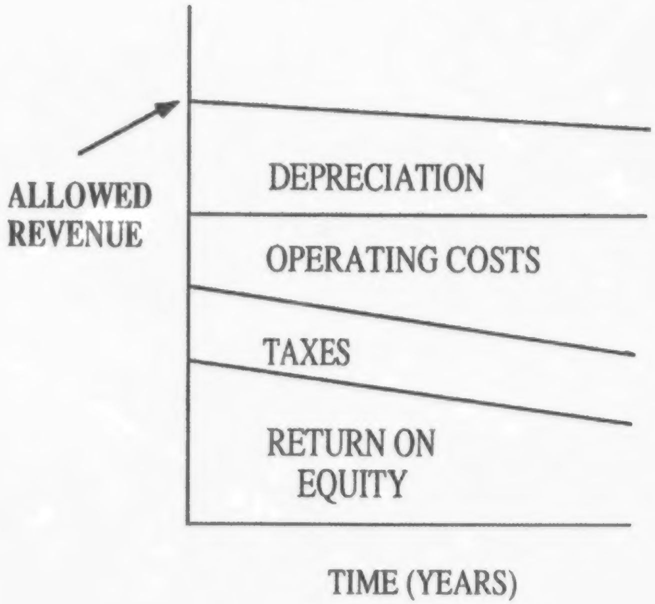
+ Normalized Carrier Operating Expenses

+ Amortization of Deferred Earnings

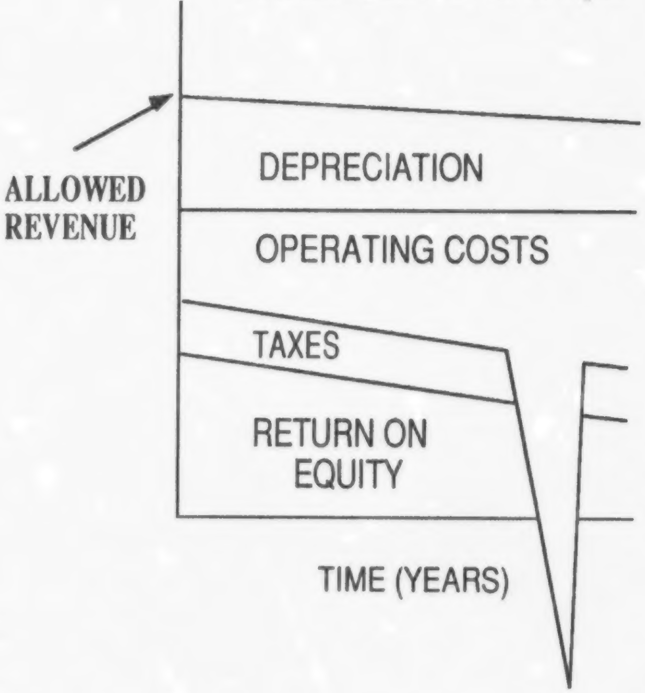
= Cost of Service

MANAGING RISK IN A REGULATORY ENVIRONMENT

Expected Outcome



Potential Effect of A Spill



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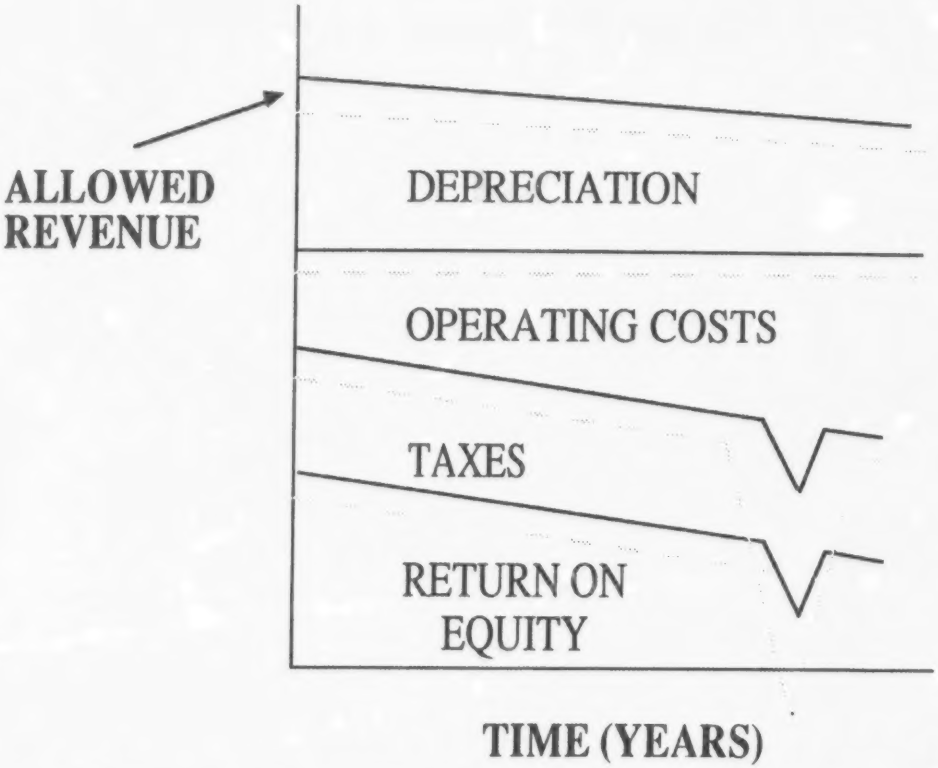
MANAGING RISK IN A REGULATORY ENVIRONMENT

THE EFFECT OF ADDING LEAK DETECTION



ERNST & YOUNG

PRICE CAP REGULATION FORMULA

CR * ((I - P - 0.5%) + E)

CR = CURRENT RATE

I = INFLATION

P = PRODUCTIVITY ADJUSTMENT FACTOR

0.5% = PRODUCTIVITY DIVIDEND

E = EXOGENOUS ADJUSTMENT FACTOR

PRICE CAP REGULATION - BUCKEYE'S EXPERIMENTAL PROGRAM ADOPTED BY THE FERC

- Buckeye Required to File Annual Reports with Commision Detailing Price and Revenue Changes in Each of its Markets
- Rate Changes in Non-Competitive Markets to Track Rate Changes in Competitive Markets
- Shippers Entitled to File Complaints or Protests Following Notice of Rate Increase in Competitive Markets
- Program Adopted on Experimental Basis for Three Years

PRICE CAP REGULATION CONSIDERATIONS

- STARTING POINT:
  - EXISTING RATES?
  - BASELINE COST BASED ANALYSIS?
- DO MECHANISMS EXIST IN THE PRICE CAP METHODOLOGY TO ALLOW FOR :
  - RECOVERY OF FUTURE INVESTMENT?
  - SIGNIFICANT CHANGES IN EXPENSES?
  - VOLUME SHIFTS?

PRICE CAP REGULATION - BUCKEYE'S EXPERIMENTAL PROGRAM ADOPTED BY THE FERC

- Commission Continues to Regulate Rates Under Interstate Commerce Act
- In Competitive Markets Individual Rate Increases:
    - Not to Exceed a 15% Real "Cap" Over Any Two Year Period
    - Allowed to Become Effective if They do not Exceed Change in GNP Deflator Since Last Increase, Plus 2.0%
- Rate Decreases Presumptively Valid
- Rate Increases in Non-Competitive Markets Will be Capped by the Weighted Average of Increases in Competitive Markets; Same Rule Applies to Rate Decreases

EMERGING ISSUES IN THE 1990'S

- RISK ALLOCATION ISSUES
- FULLY DEPRECIATED RATE BASE- COR ISSUE
    - Management Fee
- INTEGRATION OF COMPETITION INTO REGULATORY ENVIRONMENT
- RATE DESIGN AND COMPETITIVE MARKETS
- INCENTIVE REGULATION
- EFFECT OF SPILLS, DR&R, AND EXTRAORDINARY EVENTS

LEAK DETECTION PERFORMANCE SPECIFICATION

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ABSTRACT

Real-time leak detection systems have been gaining acceptance as an important tool to detect leaks in pipelines. However, there seems to be a general lack of understanding of these systems and subsequent problems in preparing performance specifications.

This paper will clarify several important points to be considered. Firstly, the pipeline company should determine its objectives and the performance level expected in terms of detection time, size of leak detected and level of false alarms under normal and degraded conditions. Secondly, the factors affecting the performance of the leak detection system should be thoroughly understood. Thirdly, the leak detection system must provide information to the user which is easily assimilated and enables the operator to make informed decisions.

INTRODUCTION

This paper examines the key considerations required to specify the performance of a transient model leak detection system when preparing a request for quotation (RFQ).

The considerations include the objectives for the leak detection system, performance specifications and factors affecting the performance.

Supervisory control and data acquisition (SCADA) systems are an integral part of pipeline operation. Effective real-time leak detection software based on a transient model has been developed and integrated with the SCADA system. As a result, real-time leak detection techniques are gaining wide acceptance as an important and practical tool to detect leaks in pipelines (Barg, Yoon, 1988).

Leak Detection techniques can be grouped into the following categories:

- leak detection by comparing inlet and outlet flows
- leak detection by comparing inlet and outlet flows with changes in linepack
- leak detection based on a transient model

This paper focuses only on transient model leak detection systems.

Transient model leak detection systems are operating satisfactorily on a number of pipelines, although some implementation efforts have not been as successful as anticipated. The unsuccessful attempts were mainly caused by misunderstanding of the technique both on the part of users and vendors. This paper is intended to clarify both the performance capabilities and the limitations of the technique.

Key objectives for leak detection are stated in the following section. The performance specification for a leak detection system is discussed in terms of detection time, size of leak detected, level of false alarms and operating conditions. Factors affecting leak detection performance are described (Bernard, Lin, 1986 and Yoon, et al, 1988). Man-machine interface issues that provide information required by the operator to make informed decisions under possible emergency situations are addressed.

The system concepts are summarized in the appendix.

LEAK DETECTION OBJECTIVES

Leak detection and containment is an important part of a pipeline operation.

In general, the objectives required from a leak detection system should include:

- reducing spillage of product resulting from leaks
- detecting and locating leaks quickly and consistently without relying heavily on the operator experience
- assisting the operator in determining and responding to emergencies and other operational situations
- satisfying regulatory requirements.

Reducing spillage has important consequences in economic and safe pipeline operations, including lower costs from product loss and spillage cleanup, smaller environmental damages and reduced community health hazards from leakage of hazardous products.

Leakage containment can minimize spillage in several ways:

- detecting and locating the leak quickly
- confirming and isolating the leak rapidly and
- reducing block valve spacing

The overall spillage volume can be represented in the following diagram.

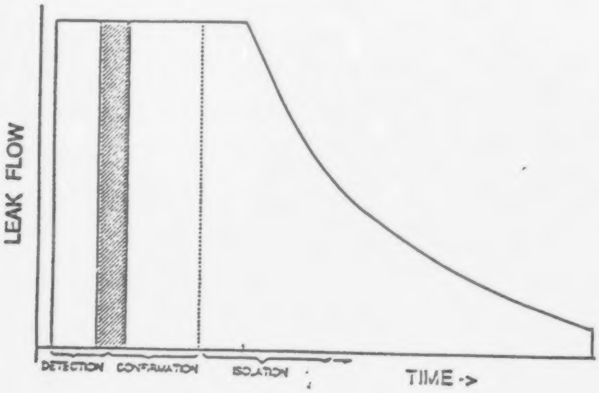

FIGURE 1 SPILLAGE VOLUME

A leak is initially detected and located by the leak detection system and then confirmed by some means such as visual inspection. After the leak is confirmed, it must be isolated by closing block valves adjacent to the leak. A significant volume of product can be lost after the leak is isolated due to terrain and valve spacing. As shown in the diagram, the spillage during the detection phase can be relatively small compared to the total spillage. Rapid leak detection time does not play a significant role in reducing spillage and should be less emphasized if spillage minimization is an overriding objective.

Experienced operators can detect leaks above a certain size without much difficulty if they are attentive all the time. However, the problems in relying solely on human judgement in detecting leaks are:

- it is difficult to distinguish leaks from other signals caused by operational problems such as column separation and instrument malfunction
- the operator cannot constantly watch for signs of leak
- human error may occur
- some inexperienced operators may not respond to an emergency properly

A good leak detection system can reduce such operator difficulties by detecting leaks without producing frequent false alarms as well as assisting the operator in responding to emergencies.

The leak detection system can also be designed as an operating tool to determine operational problems, and produce appropriate diagnostic messages for the operator. Such operational problems must be distinguishable from the leak in order to reduce false alarm frequency.

PERFORMANCE SPECIFICATIONS

The performance of a leak detection system must be specified and described in terms of the following variables:

- leak detection time
- size of leak detected
- false alarm rate
- operating conditions
- degraded conditions (loss of measurement)

Unless all of these variables are identified, the performance specification of the leak detection system has very little meaning.

Leak Detection Time

Leak detection is the most critical phase in the leak containment process and rapid leak detection is required to reduce product loss due to the leak. However, as discussed in the previous section, fast detection time alone does not necessarily guarantee spillage minimization. Rapid confirmation and isolation play as important roles as rapid detection in reducing spillage. Rapid confirmation allows fast operator response which depends largely on having a low false alarm rate. Therefore, too much emphasis on rapid detection time should be avoided in the performance specification, unless detection time is the most important parameter for some other reason.

Size of Leak Detected

The size of leak detected is considered in terms of the minimum detectable leak size and the relationship between the size and the detection time. The specification of the minimum detectable leak size can be based on the user's past experience, regulatory requirements, etc. Since the minimum size is strongly dependent on the measurement accuracy and other contributing factors, caution should be exercised in specifying this minimum size.

In general, the smaller the leak size, the longer it takes to detect the leak. This relationship results from the fact that the leak signal to noise ratio is small for small leaks but when the leak signal is accumulated for a longer period the ratio can be large enough to distinguish the leak from the noise. For relatively large leaks, the ratio is large and thus the detection time is relatively short. This is shown graphically in Figure 2. For very large leaks, however, the ratio is greater than a set threshold, so that their detection time is independent of time. Leak location accuracy is similarly dependent on the signal to noise ratio. Therefore, large leaks can be in general located more accurately than small leaks.

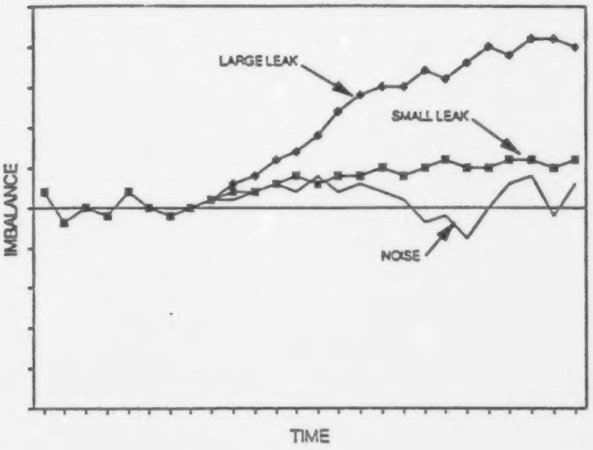

FIGURE 2 LEAK SIGNAL VS. NOISE

False Alarm Rate

The problem of false alarm is related to the frequency of false alarms and the means by which real alarms are distinguished from false alarms. The perception of false alarms differs widely among pipeline companies and pipeline operators. If the frequency of false alarms is higher than the perceived false alarm level, the operator will not depend on the results from the leak detection system. Therefore, the company must clearly define the acceptable level of false alarm. A tight leak detection time is prone to produce more false alarms. However even with current technology it is almost impossible to develop a leak detection system which does not produce some false alarms. The issue is not how to eliminate false alarms, but what level of alarm to tolerate and what information to generate to identify a true leak. This issue is discussed in the section dealing with man-machine interface.

Operating Conditions

Pipeline operating conditions are broadly classified into steady state and transient state conditions. It is more difficult to determine the state accurately under transient conditions than under steady conditions when factors affecting performance are taken into account. Although such uncertainty produced by a transient model is smaller than that produced by other simpler methods, still it is a major source in the reduction of leak detection performance. In other words, better performance can be achieved under steady conditions than under transient conditions. The factors creating uncertainty in determining the pipeline state are discussed in the next section.

Degraded Conditions

The degraded condition is defined as the case where pipeline data from SCADA is unavailable. The leak detection software will not function to its full capacity without SCADA data but should continue to provide reliable leak detection. To achieve acceptable leak detection performance, the software must compensate for missing real-time data. The leak detection system is placed into a degraded condition until normal operation is restored, primarily to avoid generating false alarms and advise the operator of limited leak detection capability. If the real-time data unavailability problem occurs frequently, the system would be in a degraded mode often. The performance problem under such a condition should be addressed in the specification.

FACTORS AFFECTING PERFORMANCE

Several external factors listed below have a direct impact on the performance of a leak detection system. These factors are typically beyond the control of the leak detection vendor and the owner must be prepared to do a good deal of preparatory investigation to ensure that such outside factors do not unduly constrain the performance of the system. The major external factors are listed below and discussed in the following pages:

- valve and instrument spacing
- instrumentation
- product properties
- pipeline operating characteristics and
- SCADA system
- data gathering devices.

Prior to approaching the leak detection vendors, a thorough review of each area should be conducted and the results consolidated. These results will then form the basis for a sensitivity study; ie, it should be possible to predict the minimum achievable performance and identify the external factors which would pose the greatest threat to reliable operation.

Valve and Instrument Spacing

The selection, location and specification of instrumentation should accommodate the SCADA and leak detection system requirements. The spacing of automated block valves has a direct impact on spillage minimization through two factors. First, a reduction in the spacing of block valves will result in a corresponding reduction in potential spill volumes. Second, closer instrument spacing will result in improved leak detection performance. However, for both spillage minimization and leak detection performance, there is a point of diminishing returns.

Instrumentation

Since the leak detection system depends on the field instrumentation, instrument quality plays an important role in achieving a high level of leak detection performance. Most industrial-grade instrumentation available today is suitable for use in leak detection system. The key factor is repeatability, which is often unclear in the specifications. The selection of instrumentation should be consistent with the expected performance. The leak detection software uses the measured values passed from SCADA, which contain the errors of the primary instrument device as well as of the associated electronic devices. Therefore, instrument specifications should cover the specifications of both the primary and associated devices including analog to digital conversion error.

Mounting of the instrumentation requires special consideration (Yoon, et al, 1988). The temperature sensor should be installed to read the true fluid temperature, in locations not adversely affected by outside conditions. The pressure measurement device must be installed to measure the accurate line pressure even when an adjacent valve is closed. If the flow measurement is corrected to a reference condition, the correction should be done consistently by using the same equation of state.

Product Properties

Often the key to successful leak detection is to know what is in the pipeline! The product properties affect the line pack and transient responses in the pipeline. In the case of tightly specified products, the properties can be closely monitored with chromatographs, densitometers, calorimeters, etc. In general, however, it is often difficult to define the properties accurately for operating pipelines transporting such products as crude oil and natural gas liquid (NGL). Nonetheless, an analysis of false alarms indicates that errors in the product properties constitute the largest cause of false alarms. If the required performance specification is tight, it is necessary to install instrumentation to quantify the product properties.

The product property problem is significant in pipelines which transport multiple products in batch. Error in batch positioning can lead to error in the modelled state and thus accurate tracking of batches by the model is important in maintaining product definition accuracy.

Pipeline Operating Characteristics

As discussed in the previous section, operating transients can cause great uncertainty in computing the pipeline state. This uncertainty results from the errors in product properties and instrumentation, the data sampling error and unique operational features which are not taken into account in the leak detection software. Particular pipeline operations should be identified and included in the operational features in the software.

SCADA System

A real-time leak detection system receives field measurement data through the SCADA system, which collects and processes the measured data. The particular manner in which SCADA collects and processes the data can impact leak detection performance. Factors such as scan time, time skew, report by exception, data gathering devices, communications, etc. should be documented as a part of the RFQ.

Scan time, time skew and report by exception are related to data sampling error in one way or another. If a variable changes rapidly and the variable is not sampled while it is changing, the change cannot be reported to the SCADA system. The shorter the scan time, the higher the measurement resolution. However, it is often impractical to reduce the scan interval, as this may require substantial SCADA and communication equipment upgrades. The data sampling issue requires a compromise between leak detection performance and the cost to implement the desired SCADA system. The largest concern in the area of communications is the introduction of time jitter to the set of readings retrieved from the data gathering devices. This can be alleviated by attaching time-tags to each set of readings or by ensuring that the scan frequency is much faster than the leak detection frequency. The former approach is usually preferred since the latter approach is wasteful of the bandwith. For volume readings this time-tag approach has been traditionally implemented using a meter freeze approach which still allows significant data sampling errors for pressure and density readings.

For leak detection systems the pertinent function of the SCADA system is to validate and consolidate the incoming data sets and pass them as a superset to the leak detection application. Most modern SCADA systems are designed to allow easy transfer of data to other applications (such as leak detection, batch tracking, and optimization) however, older (pre 1985) SCADA systems are not. See (Jacobs, 1986) for a more detailed discussion. After the application has processed the data, the SCADA system is often used to annunciate the alarms and display the results. This is usually a straight forward task.

Data Gathering Devices

Data gathering devices include Remote Terminal Units (RTU), Programmable Logic Controllers (PLC), and Flow Computers (FC).

An ideal device would gather all the readings from the instruments nearly simultaneously, at a fixed sample rate, with no jitter in sample frequency, with a time-tag on each set of readings, with a 10-12 bit analog/digital (A/D) or a 24 bit counter, and with no filtering. This ideal device doesn't exist! Each area (sampling and accuracy) should be investigated to provide the best possible signal.

MAN-MACHINE INTERFACE

A perfect leak detection system would never generate false alarms, would give an alarm only when an actual leak was occurring, detect any size of leak as soon as it occurred and give the location of the leak. Unfortunately, a perfect leak detection system does not exist.

Most leak detection systems, sophisticated or otherwise, leave the important decision of leak determination to the operator of the pipeline system. The operator's interpretation of operating conditions, incoming alarms and other factors associated with a possible pipeline leak scenario determines whether he suspects a pipeline leak.

Since the operator makes this decision, it is important that the leak detection system presents accurate and timely information. Real-time displays of leak detection information can enhance the normal alarms and status changes received from a SCADA system. Trending, logging, annunciation and displaying of all relevant data are provided by the leak detection software as a natural extension of the SCADA system. These displays include:

- leak detection alarms and line balance information
- measured and modelled flow, pressure and batch profiles along the pipeline
- historical trend of the measured and modelled data

The software produces the leak detection information such as leak status, leak location, estimated leak size, leaking product and reliability of the leak status. In the event of a leak alarm, the software should provide an on-line help facility as a tool to validate the alarm so that the operator can make an informed decision.

This type of information can be graphically displayed in a real-time environment. Some examples of these types of graphical displays follow:

- Pipeline operating pressure profiles (Figure 3)
- Material imbalances of the pipeline over certain time periods (Figure 4)
- Signature plot which provides the operator with a tool to validate the alarm (Figure 5)

A display should also be provided which shows each of the inputs to the leak detection system so that the operator may quickly see if any key values are suspect or stale. This display need not be graphical; but good results have been achieved with color coded data (for example, green: validated, yellow: suspect, red: unusable).

Also a method of monitoring the correct operation of the leak detection system should be provided. Such a method would provide control of the leak detection system (start, stop, restart, continue), over to the various leak detection thresholds, and over to diagnostic variables to ensure correct operation of the leak detection internal characteristics.

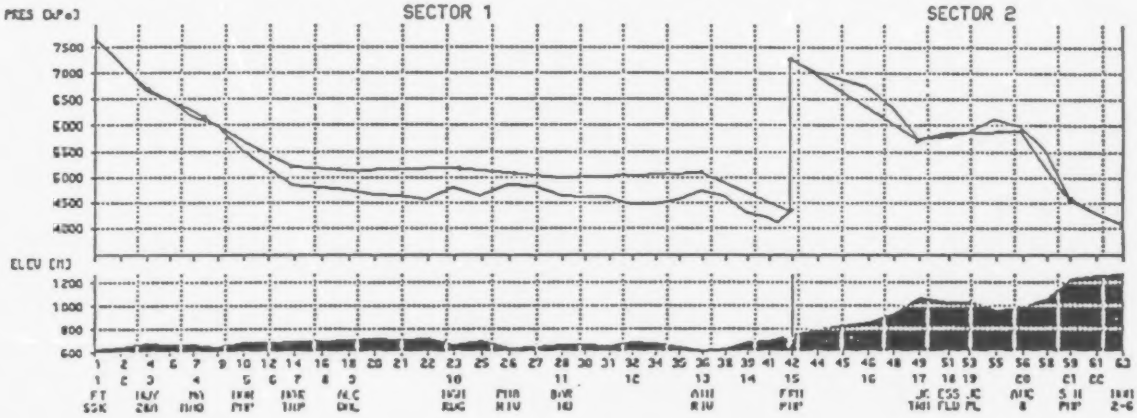

FIGURE 3 PRESSURE PROFILE

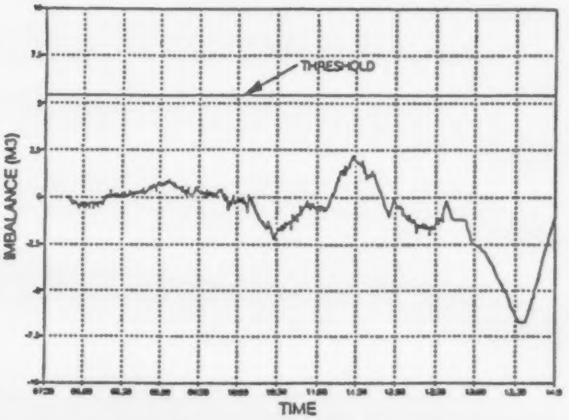

FIGURE 4 IMBALANCE OVER TIME

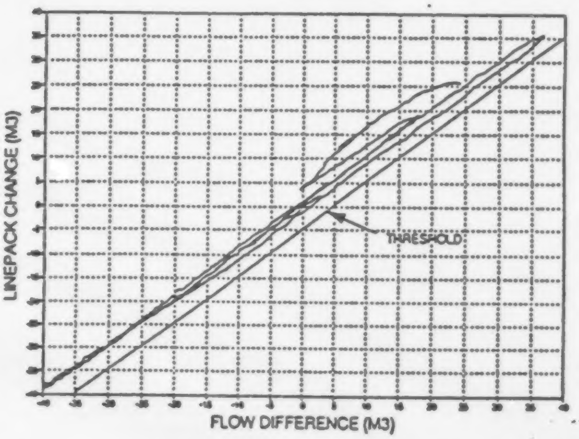

FIGURE 5 SIGNATURE

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SUMMARY

Leak detection performance specification requires a significant amount of preparatory investigation and study. Once the objectives and external factors are known, a performance level can be obtained by performing a sensitivity study, and a set of achievable functional and performance requirements can be confidently specified. Such preparatory work can ensure the successful implementation of a leak detection system.

The leak detection performance is specified in terms of leak size and its corresponding detection time, minimum detectable leak size, false alarm rate, operating conditions and degraded conditions. The system user should understand the pipeline system clearly and describe the specifications on instrumentation, products being transported, pipeline operating characteristics, and SCADA system. The requirements for an on-line help facility are specified in order to facilitate informed operator decisions in the event of a leak or pipeline upset.

APPENDIX - REAL-TIME LEAK DETECTION SYSTEM

A real-time leak detection system consists of a SCADA system and leak detection software, the functions of which are integrated by means of a hardware and software interface.

The SCADA system collects the field telemetry data and passes the collected data to the leak detection software through an interface. The collected data includes pressures, flows, temperatures, densities and other statuses available in the field. The SCADA system also receives modelled data from the leak detection software and displays it on the SCADA console.

The leak detection software consists primarily of two parts: a time-dependent mathematical model and leak detection. The pipeline state is governed by three conservation principles: momentum, mass and energy. The conservation equations are expressed as partial differential equations. These differential equations together with the equation of state are numerically solved for the pressure, flow, temperature and density with respect to space and time. The model compensates for product properties, pipeline characteristics and line configuration, so that the pipeline conditions can be accurately represented if the given boundary conditions are accurate. The mathematical model uses the data received from SCADA as boundary conditions. Since the SCADA data is real-time data, the computed pressure, flow, temperature and density profiles represent the current pipeline state.

The computed pipeline state is applied to leak detection. While there are different ways to use the computed state in leak detection technique, the essential principle is based on the mass balance principle that the difference in the inlet and outlet flows is balanced with the line pack change in the pipeline. It is assumed that a leak occurs in the pipeline if the computed imbalance exceeds the given tolerance without any other known reasons. For different set of boundary conditions, the imbalance has a different form at the point where the boundary condition is applied.

In the ideal case where no errors in measurement exist and the product is perfectly defined, no imbalances can be observed in the absence of a leak. In the real environment, mass imbalance is likely to exist in varying degrees depending on the relative interaction between various contributing factors. The size of the imbalances in the absence of leaks compared with those resulting from a leak sets the level of leak detection performance. The factors contributing to imbalances are discussed in the previous section.

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DESIGN AND PERFORMANCE OF A LEAK DETECTION SYSTEM FOR A REFINED PRODUCTS PIPELINE

CANADIAN PETROLEUM ASSOCIATION
FIFTH ANNUAL PIPELINE CONFERENCE
"Pipelines in a Changing Environment"
The Palliser Hotel
Calgary, Alberta
May 15 and 16, 1991

John A. Luopa
ESSO Petroleum Canada

Canadian Petroleum Association

Fifth Annual Pipeline Conference
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Design and Performance of a Leak Detection System for a Refined Products Pipeline

John A. Luopa
ESSO Petroleum Canada

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Canadian Petroleum Association

Fifth Annual Pipeline Conference
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Design and Performance of a Leak Detection System for a Refined Products Pipeline

1.0 Brief SCADA / Pipeline Description.

- Dual computer system with automatic fail-over to hot standby

- SCADA system running on 2 DEC 11/44's

- 15- RTU's

- 12 inch line 170 miles long, running at an average of 500 M3 per hour

- 5-Pumping Stations

- 2-Laterals to Product Delivery Terminals and an end Terminus that receives most of the products

- Turbine meters with custody transfer accuracy

2.0 Leak Detection System Features

The Leak Detection System is based on corrected volume balance (to 15 deg.C and 0 kPa) with line pack compensation. There are several program modules (Monitors) that carry out the various calculations used by the Leak Detection Monitor (**LKDMON**).

- Batch Tracking Monitor (**BATMON**) calculates the **change in linepack** for each of the 6 pipeline segments once per minute using ESSO's algorithms and the calculated average density for each segment.

- Once per minute **METER MONITOR** calculates the change in net corrected flow into the pipeline (**dFLOWin**) and the change in net corrected flow out of the pipeline (**dFLOWout**).

- **LKDMON** calculates "delta leak" (**dL**) every 2 minutes in accordance with the following equation:

$$dL = dFLOW\ out - dFLOW\ in + dLINEPACK$$

The system uses 3 “moving windows” for leak detection.

The last 5 **dL**'s are summed to produce a 10 minute value (**10MNLK**).

The last 6 **10MNLK**'s are added to create a 1 hour total (**HRLK**) and the last 24 **HRLK**'s are added to create the 24 hour total (**DAYLK**).

The **10MNLK** calculated values are statistically analyzed off line and the alarm point is set at the 3 Sigma value to reduce the number of false alarms. Based on the premise that the variation in **dL** is caused by random fluctuations in the process variables, the initial (theoretical) **HRLK** and **DAYLK** alarm points are calculated as follows:

HRLK alarm point = **10MNLK** alarm point **X** square root (60 min./10 min.)

DAYLK alarm point = **HRLK** alarm point **X** square root (24 hr./1 hr.)

These values are then adjusted based on operating experience. The current settings are:

- **10MNLK** = **-4 M3** (~ 5%)
- **HRLK** = **-15 M3** (~ 3%)
- **DAYLK** = **-60 M3** (~ 0.5%)

The theoretical detection time for leaks of various sizes is shown in **Figure 1** below.

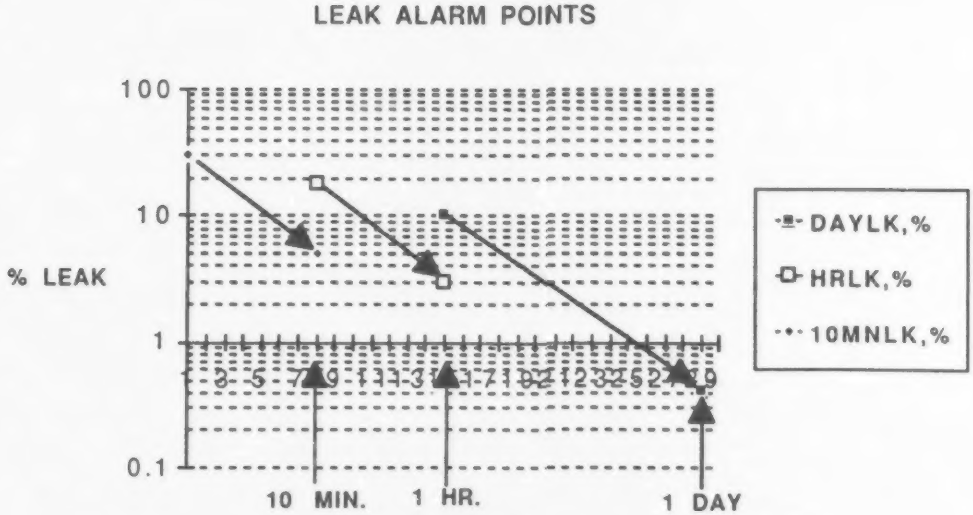


FIGURE 1

3.0 Tuning

The leak detection algorithms which were developed in-house have a total of 9 "tuning constants" which can be adjusted to reduce the number of false alarms caused by operating transients without unduly desensitizing the system to actual leaks. (the original work on the algorithms was carried out in 1986 by Mr. T.J.Cook P.Eng.who is currently the Superintendent of ESSO's Sarnia Products Pipeline).

There are: - 2 constants for average segment pressure.

- 3 for average segment temperature.
- 1 for the **dL** filter.
- 1 for startup temperature initialization.
- 1 for segment pipe expansion due to pressure.
- 1 for segment pipe expansion due to temperature.

The last 2 can be calculated from the characteristics of the pipeline but the remaining 7 can only be "tuned" during normal but infrequent, pipeline operating transients. Transients for tuning purposes have to be scheduled so that interference with normal operation is minimized. In order to speed up the tuning process, we decided to use a different approach.

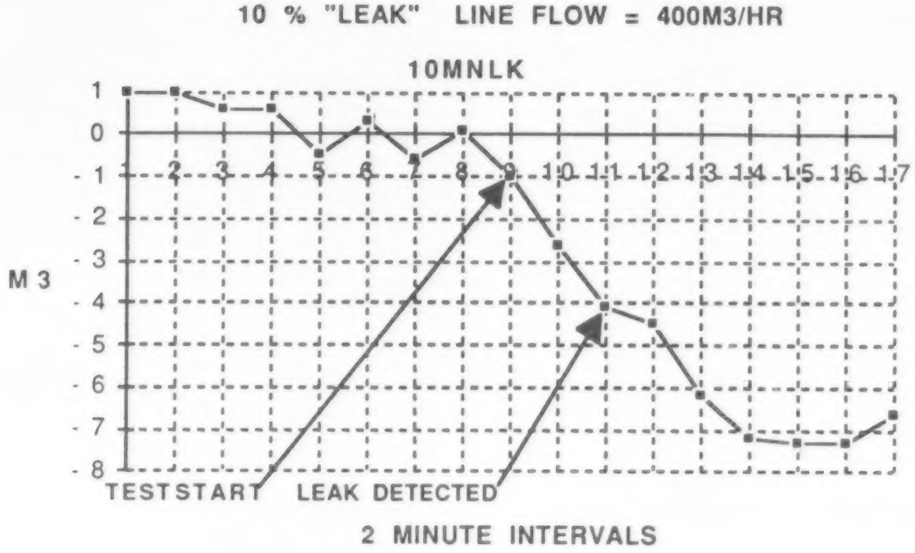
We set up a **REPGEN** report to run every minute and log all of the pipeline flows, pressures, temperatures and calculated values during various normal operating transients such as:

- pipeline startup
- pump configuration changes
- delivery to a terminal
- changing product at the initiating station

The data were then transferred to a spread sheet with each variable in a column and the leak detection algorithms, which are mainly recursion formulas, were entered into adjacent columns. Each row represented a time step of 1 minute. The algorithms were initialized and the spread sheet was rerun several times with various tuning constants. Operating experience has confirmed that the constants chosen are close to optimum

4.0 Test Results

The leak detection system was tested by starting a flow of 10% of line rate to an intermediate terminal with the terminal RTU "off-scan" so that terminal flow was not seen by the host. The leak alarm was detected after the correct time interval. **Figure 2** below shows the test.


10 % "LEAK" LINE FLOW = 400M3/HR

10MNLK

FIGURE 2

The system has demonstrated the ability to ride through pipeline transients without creating a false alarm. **Figure 3** below shows a particularly severe transient where the initiating station temporarily lost suction pressure. Flow into the pipeline was drastically reduced for about 15 minutes. During the transient **10MNLK** showed a maximum of **+2.5 M3** and a minimum of **-3 M3** which is above the alarm point of **-4 M3.**
(**Note:** The graph only shows the first 12 minutes of the transient).

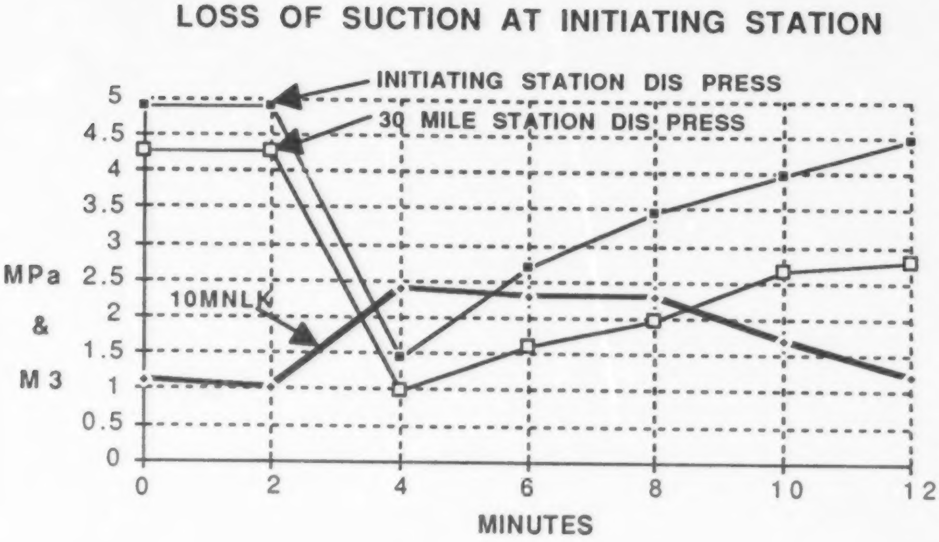


FIGURE 3

5.0 Problems Encountered

Several problems that affected leak detection were discovered during system commissioning.

5.1 There is a "time skew" inherent in the system between the RTU scans and the running of leak detection that can cause false alarms. A **dL** filter was installed to solve this problem. **Figure 4** illustrates the effectiveness of this filter.

5.2 The time rate of change of segment average temperature is more critical than pressure to accurate calculation of **dLINEPACK** because **1 deg.C** has about the same effect on linepack as **1000 kPa**. The pipeline transports a variety of products that are stored in above ground tanks at the initiating terminal. There are significant temperature variations from tank to tank. If **Tave** was a simple average of the segment inlet and outlet temperatures, swinging from one product to another would cause a large error in **Tave** (and **dLINEPACK**), especially in the first pipeline segment. A special filter that takes into account flow rate and segment volume simulates product movement down the pipeline and successfully solves this problem. **Figure 6** shows a typical product swing where **Tave** in the first segment smoothly changes from **13 deg.C** to **16 deg.c**.in the correct time frame.

5.3 The product temperature transmitters quickly read ambient temperature after a pipeline shutdown. This can cause a large error in **Tave** for the pipeline segments leading to an error in **dLINEPACK**. Because of the **Tave** filter shown in **Figure 6**, the error in **Tave** can last several hours. Temperature initialization logic shown in **Figure 5** solved this problem.

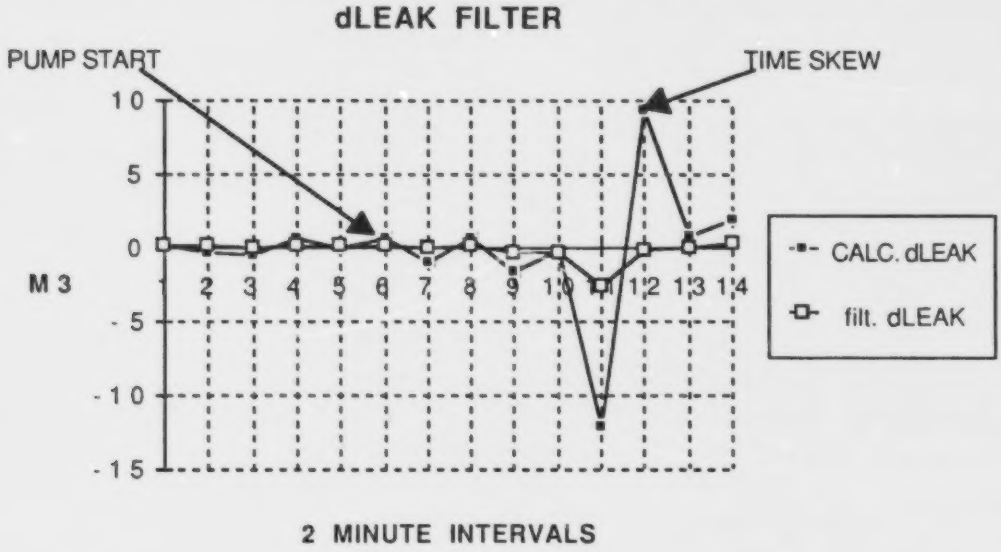


FIGURE 4

5.4 Large **dFLOWin**'s and **dFLOWout**'s leading to large apparent leaks were experienced after a cold SCADA startup. A programmable delay was installed to inhibit the running of leak detection for one program pass after a SCADA startup so that the first delta flow calculation will be correct.

5.5 The SCADA system RTUs "report by exception" to the host. To ensure that the host computer isn't missing any field data, an integrity check **(INTEGS)** is carried out periodically (once per day) where all of the RTU data is scanned. **INTEGS** creates a problem when it runs on an RTU that reads a meter included in the leak detection envelope. This is because **dLEAK** is still being calculated even though the affected meter's counts remain stale until **INTEGS** is finished. Up to 4 false alarms were created each day by **INTEGS**. This problem was solved by bypassing the **dLEAK** calculation (for a maximum of 2 passes) when a "zero" **dFLOW** is detected.

TEMPERATURE INITIALLIZATION LOGIC

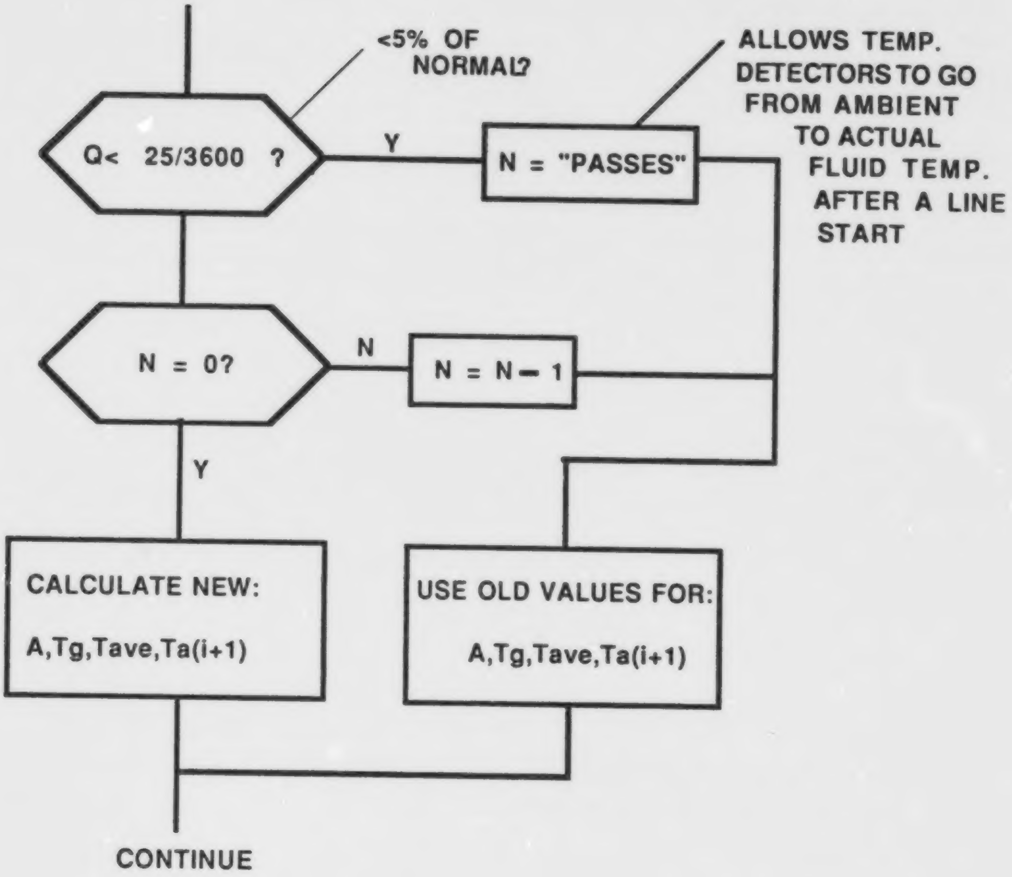
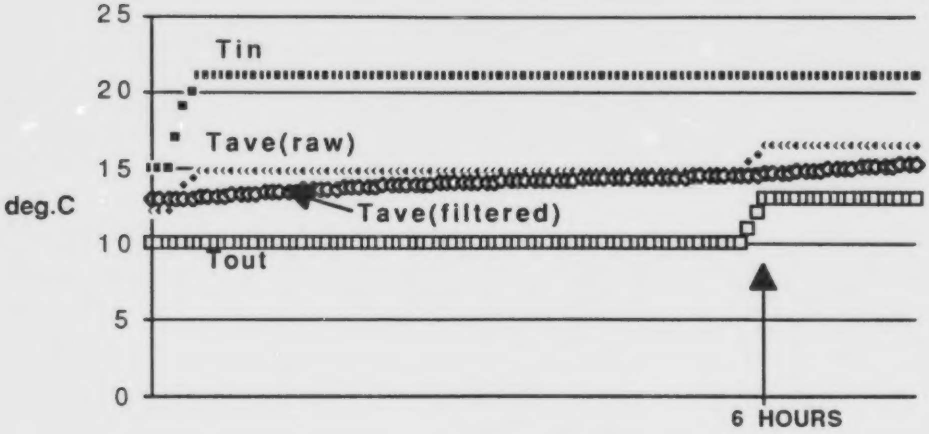

<5% OF NORMAL?
Q< 25/3600 ?
Y
N = "PASSES"
ALLOWS TEMP. DETECTORS TO GO FROM AMBIENT TO ACTUAL FLUID TEMP. AFTER A LINE START
N = 0?
N
N = N − 1
Y
CALCULATE NEW:
A,Tg,Tave,Ta(i+1)
USE OLD VALUES FOR:
A,Tg,Tave,Ta(i+1)
CONTINUE

FIGURE 5

SEGMENT Tave Filter



TIME, HR.

FIGURE 6

6.0 Operator Acceptance.

The operators have been trained in the use of the system. The low frequency of about five false alarms per week and the successful tests have given the leak detection system a high level of credibility. An operating manual has been issued that spells out the following procedure for the operator to follow should an alarm occur:

- All alarms must be analyzed to determine whether they were caused by a change in operation such as a line startup or by a system action such as **INTEGS** or by a failure such as a loss of communications to an RTU.

- If the alarm cannot be explained then the pipeline is shut down and blocked in and the segment pressures are monitored.

7.0 SCADA Vendor Support.

The vendor's field support staff is motivated and qualified to correct errors and to make software modifications. The support staff reacts quickly to program "bugs" but enhancements have a lower priority and can take a long time to implement.

All changes are tested in Calgary and simple ones are downloaded via modem to site. All major modifications are installed at site because downloading is considered to be too risky.

8.0 Lessons Learned

The specification for leak detection should have covered initialization and measurement rationality checks in more detail.

Leak detection should have been designed so that loss of communication with or running of **INTEGS** on certain RTUs will not create false alarms.

In order to eliminate time skew, leak detection should run only after all meter counts are updated either by a "meter freeze" command or through the use of flags.

9.0 Maintenance

The turbine meters are proved at least once per quarter on each product. The system automatically uses the correct meter factor for the product being measured.

Critical pressure and temperature transmitters are checked at least once per year. Absolute accuracy in pressure and temperature measurement for the pipeline segments is not essential as long as the gain (slope) of the output signal to the input variable is correct. This is because the leak detection algorithms calculate the **change** in line pack from the **change** in pressure and temperature. This is in contrast to most Real Time Transient Models that require accurate pressure and temperature measurement to allow correct solution of the equations. Most transient models need to incorporate an automatic calibration feature to get around transmitter drift.

Statistical analysis of **10MNLK**, **HRLK** and **DAYLK** is an ongoing activity to ensure that the alarm points are correctly set for the current operating conditions and to detect any developing measurement problems.

10.0 Future Enhancements

One of the enhancements we are planning is to replace the three alarm "windows" with what we call a "continuous alarm point" (**CAP**) that would present a single alarm to the operator and detect intermediately sized leaks more quickly without increasing false alarm frequency.

The concept is illustrated in **Figure 7**. It can be seen that for a 4% leak the **HRLK** alarm would occur in about 50 minutes whereas **CAP** would alarm in about 30 minutes. Similarly a 2% leak would be detected by **DAYLK** in about 400 minutes and by **CAP** in about 120 minutes.

"CONTINUOUS" ALARM POINT vs "WINDOW" ALARM POINTS

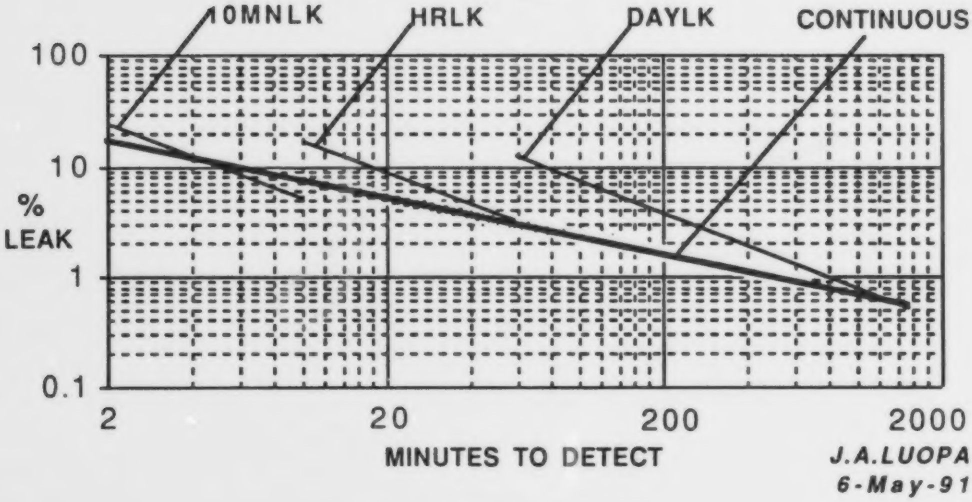


FIGURE 7

Reconciling Pipeline Development Within Alberta's Allocated Forest

by

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May 1991

Introduction

During the 1970s, soils conservation was a major issue for pipeline developers, an issue that was concrete and well understood by all interested parties. The goal was continued agricultural land productivity. With the advent of the 80s, the Alberta provincial government articulated a strategy of economic diversification, based on expansion of Alberta's primary resources. That decade saw significant expansion by the forestry sector, creating potential conflict with the oil and gas industry, with issues related to access rights, timber values and compensation assessment, combined with increased public concern about air and water quality, land and resource management. These issues will continue to demand attention, but as the 1990s unfold, we will be faced with the additional, more complex and much less tangible challenges of sustainable development and integration of renewable and non-renewable resource management.

In my presentation today I would like to review NOVA's approach to co-management of public lands. I will briefly discuss the issues of regulation, forestry sector growth, timber resource values, land withdrawal and forest management, as they relate to pipeline expansion. I will also discuss and make some recommendations regarding the more complex, less tangible issues facing us in the coming decade.

Regulation

All pipeline construction in Alberta is subject to regulatory application and approval processes. The major regulators are the Energy Resources Conservation Board, Alberta Environment and the Alberta Department of Forestry, Lands and Wildlife.

The Energy Resources Conservation Board, under the Pipeline Act, provides definitive approval to construct a pipeline, with consent from the Minister of the Environment. The mandate of the Board is to ensure the economic, orderly and efficient development of energy resources; safe and efficient practices for construction and operation of facilities; and to control pollution and ensure environmental protection in the public interest.

The major environmental review for new pipelines is conducted by the Regulated Surface Operations Branch of Alberta Environment under the Land Surface Conservation and Reclamation Act. While the process is thorough and complex, it only applies to regulated pipelines, accounting for less than five per cent of total surface land withdrawal approvals. (Regulated pipelines are those which are longer than 16 kilometres and larger than 150 millimetres in diameter.) The application must outline acceptable route location, environmental impact assessment and environmental protection planning for construction and reclamation.

Other approvals are required from Alberta Forestry, Lands and Wildlife. The Special Lands Disposition Branch administers the Public Lands Act and provides for the withdrawal of public land by Pipeline Lease Agreements (PLAs) for all pipeline construction and operation, subject, however, to certain provisions and conditions. Conditions might typically include the coordinated interests of various interested government branches or agencies, particularly Forest and Wildife Management. This process also provides for consent requirements from prior disposition holders, such as timber, grazing or agricultural entities.

The Alberta Forest Service, under the Forest Act, provides for the management of tenured, land-based Forest Management Agreements (FMAs), as well as non-tenured volume-based crown forest management units. FMAs transfer the rights and responsibilities to the forest industry for the sustained and integrated management of forest resources on a defined land base. For example, in exchange for the right to harvest timber, the forest company would undertake to sustain wood fibre growth, and manage wildlife habitat in the public interest. With the volume-based approach, the crown keeps the rights and responsibilities for forest management, allocating an allowable harvest to smaller timber operators.

There is a wide range in the type of approvals and applications for these regulatory bodies -- some applications are short and simple, others more complex and time-consuming. And while there is often a provision for multi-agency review, the individual regulating bodies may impose conditions which conflict with other regulators.

Forestry Sector Expansion

A major issue for pipeline developers -- and other interest groups as well -- will continue to be the expansion of the forestry sector, which began in 1985, when the Provincial Government established the Forest Industry Development Division. The Division's mandate was to broaden Alberta's economic base from reliance on the oil, gas and agricultural sectors. In 1987, the forest sector was a $1 billion industry employing 10,000 people. Expansion by the end of the 1990s is expected to result in the industry being valued at $3 billion, and employing 18,000 people.

So far, the expansion effort has been successful. By the end of 1991, the Province will have allocated 11 FMAs. These, combined with reserve areas and crown forest management units, will result in 85 per cent of Alberta's annual wood fibre growth being committed for timber management. The issue being raised here is land rights assignment, or how to determine whether the land under consideration would be best used for timber or for pipelines, or for other uses. Obviously, potential for conflict increases with an increasing number of parties interested in using the land.

Timber Resource Value

A major issue facing pipeline developers today is the increased cost for salvage and disposing of merchantable timber, compared to in the past, when timber was often burnt or used for purposes which today might be considered unsuitable. Let me review some of the events leading up to this problem.

In 1986, the United States challenged Canada's crown timber fee assessment, claiming that the assessment did not reflect true market value of the forest resource and gave the Canadian industry an unfair advantage over the U.S. industry. In response, Canada implemented a self-imposed 15 per cent export tariff for forest companies exporting to the States. In response to that move, Alberta initiated a review of crown stumpage fees assessed against the forest industry.

The provincial economists were sensitive to export interests and the loss of productive timber due to industrial land development. They revalued timber assessments firstly to assess crown royalties for the harvest of timber from crown lands, and secondly, to provide fee compensation for timber damage resulting from the use of the land for industrial development.They also included rates for deciduous timber, as a market for Aspen was being established. Deciduous timber had not previously been assessed.

The result of these deliberations will mean greatly increased costs for the pipeline industry, for the disposal of merchantable timber. Also raised are questions regarding the value of the forest resource and suitable uses for merchantable timber.

Table One shows the Forest Stand Damage Assessment for a mix of coniferous and deciduous forest cover, assuming a mature, fully-stocked forest stand and a harvesting cost of $13.41 per square meter for coniferous and $12.26 per square meter for deciduous, salvaged and decked at roadside.

TABLE ONE: Forest Stand Damage Assessment for land-based FMAs

Forest Cover Type	1981 Value/Hectare	1991 Value/Hectare
Coniferous	$2234	$3348
Conif./Decid.	$1407	$3212
Decid./Conif.	$825	$2899
Deciduous	$0	$2350

As can be seen in this table, the deciduous forest shows the most dramatic increase in values. However, coniferous values also increase by 150 per cent. By comparison, stumpage values would generally run somewhere between $200 and $500 per hectare in 1991, or approximately one tenth the cost.

Table Two shows timber damage assessments for volume-based crown timber allocations. The crown assesses a weighted average fee based on calculated hectares of land withdrawn.

TABLE TWO: Timber Damage Assessment -- Volume-based

Crown Assessment	1981 Value/Hectare	1991 Value/Hectare
Coniferous	$176.43	$680.00
Deciduous	$0.00	$205.00
TOTAL	$176.43	$885.00
Administration fee	$37.59	$100.00/invoice
Re-Use Charge	$46.19	$55.00

Again, the deciduous component comprises the most dramatic increase in assessment. As well, conifers show an increase over the ten-year period of 385 per cent. Overall average increase is in the order of 500 per cent, compared to the previous assessment.

Clearly, if the pipeline industry is to undertake responsibility for salvage and suitable use of merchantable timber, then it would be appropriate to exempt that timber from damage assessment, thus alleviating such a dramatic increase in the cost burden borne by the pipeline developer.

Land Withdrawal

Land withdrawal is generally a fairly straight-forward process, but not without its own issues and concerns. In this area, NOVA has demonstrated initiatives to facilitate the processes and make them more efficient. I will now briefly review the areas of pipeline lease agreements, temporary work space requirements and consent to withdraw.

Pipeline Lease Agreement applications tend to focus on tangible land-use issues, such as shared dispositions and right-of-way widths. The emphasis for forest land managers has been to encourage the use of existing disturbed lands for pipeline development, thus allowing more forest land to be available for wood fibre production.

In contrast to the environmental review process, land withdrawal by Pipeline Lease Agreement requires a single-page application accompanied by legal survey drawings. A 15-day approval process, including conditions and fee assessments is typical. NOVA has helped to facilitate this process by meeting with regulators prior to filing an application. At this meeting, issues related to integrated land use and shared dispositions are raised for discussion before a commitment is made to undertake an expensive legal survey.

Temporary work space requirements, especially for large diameter pipelines, has become a recent issue due to the need for consensus by both Forestry and Alberta Environment Reclamation officers for on-site field approval .

Recently, NOVA has undertaken to identify temporary work space requirements at the application stage, for both the Pipeline Lease Agreement and Development and Reclamation, in order to facilitate the field approval process. Aside from typical locations requiring additional construction space such as river, creek and road crossings, NOVA has initiated a field assessment team to identify potential locations for temporary grade spoil placement. While this process is not intended to provide prior authorization for clearing, it has facilitated field approval.

Consent to withdraw from FMA holders has been obtained relatively easily. Of course, the FMA holder has always regarded compensation for timber damage as the pipeline developers' cost of doing business. More recently, however, concerns over increased withdrawal from productive forest land have resulted in the need for more information dissemination and negotiation to facilitate approval.

When some form of economical use is demonstrated for the land base, timber damage assessments for land withdrawal compensate for replacing lost wood fibre. The forestry industry then is able to purchase make-up wood from other sources.

However, the expansion of the forestry industry has had an impact on this practice and created two new problems. Firstly, the forestry industry may not be able to replace the FMA land base lost to other users. As I mentioned earlier, 85 per cent of the forest has already been allocated.

Secondly, the trend toward full utilization of wood fibre will significantly affect make-up wood supplies, and may create a potential market for salvaged timber from industrial development, where it has not been economical in the past.

Ultimately the expansion of the forest sector land base for production of wood fibre will result in a fully allocated forest. Replacement lands for sustainable wood fibre operations will no longer be available. Merchantable timber from industrial developments will be valued and perhaps market competitive. These issues place industry in potential conflict with the forestry sector. Never has the need been greater for a cooperative approach to the timely and economical use of merchantable timber.

Forest Management

An important concept in forest management today is "No Net Loss". Within a defined land base, No Net Loss employs intensive forest management techniques so that when a portion of the land is removed for industrial or other uses, the remaining portion will increase in productivity and yield. The increase in productivity and yield of the remaining land should compensate for the lands withdrawn.

While forest management responsibilities have usually been assumed by the forestry industry, the OSLO and Caroline oil and gas development projects in Alberta have seen oil companies taking on responsibility for forest management. The companies involved will be accountable for managing off-site forest stands, perhaps setting a precedent for other industries.

The issue of who should be undertaking responsibility for forest management -- the forest industry or the industrial developer -- is certainly open for consideration. However, FMA holders are currently provided fee compensation for long-term loss of forested lands. An FMA holder is required to implement forest management practices that make provision for long-term wood supply. For volume-based lands, crown fee assessments could be viewed as including compensation for lands withdrawn from long-term forest production.

However, in both cases, the fees are paid to general revenues and are not dedicated to intensive forest management practices. Thus, the cost for forest management will become an increasing burden with the trend to more intensive "No Net Loss" practices. Clearly, a better, more meaningful long-term accounting procedure is required to encourage adequate management.

Issues Summary

Just to review briefly, one of the major concerns facing pipeline developers is the need to rationalize the regulatory process, to ensure that the objectives of the various regulators are aligned and to encourage the development of a complementary and streamlined process for approval of PLAs and environmental issues.

A second concern relates to land management and includes practices of timber salvage, reduced widths, shared dispositions and No Net Loss, how these practices will be conducted and who will be responsible for them.

A third concern relates to fee compensation and the allocation of fees to general revenues. Originally intended to compensate for loss of timber and for long-term withdrawal of land available for timber production, fees should be targetted to intensive forest management of the remaining land, which is only common sense.

To put these issues in perspective, they are really all components of a much broader issue -- land use integration. As the forestry sector continues to expand, we will see more and more emphasis being placed on integrating renewable and non-renewable resource development. An informed public, becoming more aware of the finite land base, will demand accountability from resource companies and the government. All land users will have to cooperate more fully to resolve conflict. And some sectors will need to recognize that provincial revenues and the quality of life in Alberta depend on strong economy, and balance that priority with the need for environmental quality of air, water and land.

On the industry side, both oil and gas and forestry must become aware of joint interests and develop cooperative means to facilitate timely resolutions of problems. It is in the best interests of both sectors to encourage the efficient utilization of merchantable timber. On the other hand, it is not reasonable to expect, for example, that the oil and gas industry capitalize mechanized logging equipment, which is only needed for a short season of clearing right-of-way. Equipment, employment and contractual flexibility will be needed to realize the potential of the two resource sectors.

Finally, let me put forward some points for consideration to help resolve the challenges I have just described:

1) The oil and gas industry, the forestry industry, Alberta Forestry, Lands and Wildlife and Alberta Environment must all work together to develop an effective integrated resource management strategy.
2) To realize the effective utilization of wood fibre, there must be a joint industry commitment to facilitate economical salvage and suitable use of merchantable timber .
3) Agencies and industry should review the discrepancies between the various regulatory processes, in recognition of a higher level of project-based planning and long-term integrated land management.

Undertaking such initiatives would be small, first steps in improving how we manage our land. Alberta has always been and will continue to be a resource-based province. Our economy has been based on the oil and gas industry and agriculture. Now, with the provincial diversification strategy, the forestry industry will be playing a more important role than in the past. In order to realize the goal of sustainable development for our province, all sectors will need to understand their individual roles in the economy, as well as to appreciate how the other sectors fit into the "big picture". Cooperation and co-management will be the cornerstone of our province's future.

PLANNING FOR WOODLAND CARIBOU
A GROWING INDUSTRY CONCERN

by

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Robyn G. Usher[3]

Abstract

Conflicts between woodland caribou (*Rangifer tarandus caribou*) and petroleum exploration and development have increased in recent years. Recent restrictions imposed by provincial agencies on industry activities in attempts to reduce impacts on caribou have resulted in lost time, information and revenue, and have prompted concern within the energy sector.

Caribou are sensitive to impacts resulting from resource development. If this threatened species is to survive in Alberta, a strategy is required that will integrate the goals of industries, government, natives, and the public.

This paper reviews the concerns of the petroleum industry, the nature of woodland caribou, past caribou research and management efforts, and current caribou-related initiatives that will have a bearing on oil and gas activities in Alberta. Recommendations are made for mechanisms to integrate the objectives of the petroleum industry with those of caribou managers.

1.0 INTRODUCTION

As a threatened species, caribou will become increasingly important in the planning process of petroleum companies operating in central and northern Alberta. The announcement by Alberta Forestry, Lands and Wildlife (AFLW) of a new policy dealing with oil and gas development on caribou range, combined with the cancellation of several seismic programs in the province during the winter of 1991 to prevent the disturbance of caribou, has led to concern within the petroleum industry (e.g. Menzies 1990).

Measures that will be imposed on industry activities to reduce impacts to caribou include: timing constraints, access limitation and control, activity mitigation, and facility placement. Given the emphasis on caribou management emerging from AFLW policy, the major goal of the petroleum industry should be to effectively incorporate those measures into their exploration and development programs.

In this paper, we review the nature of woodland caribou, past caribou management and research efforts in Alberta, and current caribou-related initiatives that will have a bearing on oil and gas activities. In Section 5.0, we suggest mechanisms for the integration of petroleum industry and caribou-management objectives.

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2.0 THE NATURE OF CARIBOU

Woodland caribou occur across the boreal forests of Canada, from Newfoundland to the Yukon. In Alberta, there are 2 "ecotypes" of woodland caribou which differ primarily in their behaviour:

- "Mountain" caribou, which summer in the Rocky Mountains and winter to the east on provincial lands where they may come into conflict with resource development; and,

- "Woodland" caribou, which remain year-round in the foothills and boreal forest. Many populations of the woodland caribou ecotype are vulnerable to impacts from resource development throughout the year.

Typically, both ecotypes occur in small groups of 1 to less than 15 animals, at exceedingly low densities (1-3 caribou/100 km^2). Because of this, and because they occupy dense conifer forests, caribou are rarely observed. Their inconspicuous nature has led to a perception that impacts either will not occur or will be minor because so few animals will be affected. Unfortunately, this is far from the truth.

Caribou are particularly vulnerable to impacts from human activity and habitat disturbance. The reasons include:

- their dependance on mature forests (50 to over 120 years old), where lichens, their primary food source, occur in greatest abundance;

- a requirement for space to avoid predators. Caribou typically do not fare well when their range is reduced in size, or when habitat alteration increases the number of other prey species in the area (thereby attracting predators);

- exposure to harsh winter conditions. In an attempt to avoid other prey species (deer, elk, and moose), and consequently reduce their exposure to predators, caribou winter in areas of relatively deep snow and may be physically stressed from November through April in some years;

- a low reproductive rate (females bear only 1 calf each year) and high adult mortality;

- traditional movement patterns and innate curiosity that make them vulnerable to illegal and native harvest (caribou often suffer high mortality from hunting in areas of newly created access); and

- fragmentation of the provincial range which has isolated many groups, further increasing their vulnerability.

3.0 BACKGROUND TO CARIBOU RESEARCH IN ALBERTA

Caribou are distributed throughout much of west-central and northern Alberta. Since the mid-1960's, the total provincial caribou population has declined from 7,000-9,000 animals to less than 2,500 (Edmonds 1986; J. Edmonds, AFWD, pers. comm.). The reasons for the decline are not well understood. A number of factors (rather than a single agent) were likely responsible, and could include over-hunting, hard winters, increased predation, and habitat disturbance (Edmonds 1986). In 1981, all sport hunting of caribou was banned. In 1985, the species was classified as "Threatened" under the Alberta Policy for the Management of Threatened Wildlife. Caribou are considered "Endangered" under the Wildlife Act.

Most of our understanding of woodland caribou in Alberta has come from research conducted by Alberta Fish and Wildlife Division (AFWD) in the west-central region (Edmonds 1988; Edmonds and Bloomfield 1984). The studies, begun in 1979, have provided important information on caribou population status, distribution, movements, and habitat use. Data from the project were used as the basis for a Provincial Restoration Plan developed in 1986 (Edmonds 1986). That plan offered a number of recommendations for management actions, including population monitoring, sanctuary establishment, public education campaigns, habitat management, and predator control.

Knowledge of caribou in the remainder of the province is much less complete. Low densities, combined with the thick coniferous forests inhabited by the animals, makes adequate data difficult to obtain. A major study of the woodland caribou ecotype was conducted in the Birch Mountains area in the late 1970's (Fuller and Keith 1981). Two detailed studies of the mountain caribou ecotype have been conducted in the Rocky Mountains (Brown 1991; Stelfox et al. 1974). Other investigations in the province have been brief and restricted to localized areas. In many regions, even the distribution of the animals remains unknown.

4.0 CURRENT INITIATIVES

A wide range of initiatives are underway to fill the gaps in baseline data. Procedures and policies are also being developed to foster sound management of caribou. These initiatives are listed below, by agency or sector.

4.1 Provincial Government

- Portions of the Caribou Restoration Plan (Edmonds 1986) have been implemented, primarily in the west-central area. Measures undertaken include continued monitoring of populations, modification of timber harvest procedures, habitat studies, the creation of road sanctuaries on some caribou ranges, and limited public information programs.

- AFWD is developing a provincial inventory strategy to set regional priorities for data collection. In each of the 3 regions where caribou occur (Northeast, Peace River, and Eastern Slopes), priorities will be set for data collection on distribution, habitat use, and the effects of resource development on caribou.

- AFLW is developing policies for Oil and Gas and Forestry activities on caribou range. These policies will provide approaches and guidelines for development. An important aspect of the oil and gas policy is the provision for "Standing Committees" to be convened to deal with and to coordinate activities in individual caribou areas.

- Multi-year studies based on radio telemetry are currently underway on caribou populations in the Pelican River (Northeast Region), Chinchaga (Peace River Region), and Little Smoky (Eastern Slopes) areas.

4.2 Forest Industry

- Procter and Gamble Cellulose and Alberta Newsprint have started programs to map caribou habitat and to assess caribou response to logging in their respective Forest Management Agreement (FMA) areas. Alberta Pacific is currently assessing their wildlife programs and will conduct caribou investigations in the future. Other forest companies whose FMAs include caribou range have made provisions for habitat protection and harvest modification in their long-range operating plans.

4.3 Petroleum Industry

- The Canadian Petroleum Association (CPA) has formed a Petroleum Industry Caribou Steering Committee to examine caribou-related issues. The committee's objectives are to determine research priorities, to develop funding mechanisms for research, and to provide input to provincial government policy.

- Companies active in the Pedigree area of northwestern Alberta have formed a working group to deal with caribou issues. Initiatives to date have included aerial monitoring, habitat mapping, and protection planning.

- Several companies are contributing to on-going studies being conducted by AFWD or by forest companies.

4.4 Integrated Programs

- The Greater Jasper Ecosystem Caribou Research Project is providing information on mountain caribou. The project, begun in 1988, has fostered cooperation among more than 25 sponsors, including provincial and federal agencies, energy companies, forest companies, and private conservation groups.

- The West-central Alberta Caribou Technical Working Group, a joint effort of AFWD and the Greater Jasper study team, has brought together parties concerned with resource development in west-central Alberta.

The petroleum industry, forest industry, provincial and federal governments, academics, and private conservation groups are represented. The objectives of the working group are to:

- exchange information;
- identify data gaps and information needs,
- exchange views on the most effective allocation of limited funds and manpower in meeting those information needs; and
- review work in progress.

Studies funded by Procter and Gamble and Alberta Newsprint are being conducted in accordance with this group's objectives.

5.0 SOLUTIONS - WHERE DO WE GO FROM HERE?

Caribou will become an increasingly important consideration of the petroleum industry within an integrated planning framework. Current initiatives are an important start. However, knowledge about caribou in much of the province and about the effectiveness of mitigation measures is scanty. Many area-specific issues remain to be resolved.

Until now, most caribou projects funded by the petroleum industry have focussed on short-term, local concerns related to specific projects. This perspective must change if sound caribou protection measures are to be developed and if those measures are to be integrated effectively into the development objectives of the petroleum industry.

There are 2 keys to success in integrating the needs of caribou with those of the petroleum industry: a provincial perspective and a long-term view. A provincial framework identifying research priorities and needs will allow the relevance of data from individual programs to be recognized and will reduce the potential for redundant and ineffective programs.

There is concern within the industry that while a great deal of money has been put toward caribou studies, there have been few tangible benefits. The lack of benefits is due largely to the lack of a framework for understanding information that is collected. If information gaps are not formally identified, results from disparate programs cannot be linked easily and do little to further our understanding of caribou biology or of the animals' responses to activity.

A long-term view is required because impacts and the effectiveness of mitigation measures cannot be assessed over a short period of time. Under highly variable environmental conditions, data must be collected over a period of years to establish and confirm trends.

To achieve the goal of developing a long-term, provincial perspective of petroleum development within caribou ranges, 4 major elements must be addressed: information; education; communication; and cooperation. Each is discussed separately below.

5.1 Information

Biological research is often considered an esoteric and impractical activity conducted primarily for the personal gain of biologists. However, little is known about caribou compared to more-common species such as elk or deer. Prior to 1980, little research had been done on woodland caribou anywhere in Canada. We are still in the early stages of understanding the basic biology of this species. Questions remain about even such fundamental aspects as distribution and habitat use. Before suitable and consistent mitigation measures can be implemented, these questions must be answered.

There is another, more pragmatic reason for collecting biological information. The Energy Resources Conservation Board (ERCB) will be placing increased emphasis on thorough baseline environmental information when reviewing and approving development applications, and caribou are of particular concern to the Board (R. Creasey, ERCB, pers. comm.). Therefore, applications for activity within caribou range may not be approved without basic information on caribou numbers, seasonal distribution and movement patterns, and habitat.

The need for information also encompasses a need for monitoring. Oil an gas companies would like some assurance that the costs of implementing mitigative measures are justified, and that the measures produce the desired result. Therefore, the effectiveness of mitigative measures must be evaluated.

CPA's Caribou Steering Committee is well positioned to provide the long-term, provincial framework for caribou studies required by the petroleum industry. Specific programs, developed through Standing Committees (convened under AFLW's policy for oil and gas development on caribou range), can then be tailored to meet provincial as well as local objectives.

5.2 Education

Education within all sectors is essential. Industry representatives must become better informed about caribou and the problems related to caribou management. Government wildlife managers must become more aware of the options that are available when special operating or development conditions are required. The native groups and the general public must be made aware of the problems associated with access, with caribou management in general, and with the efforts taken by the petroleum industry to minimize impacts to caribou.

For the industry, a sound understanding of the potential problems posed by caribou-related mitigation measures can save time and money. For example, knowledge of how and when timing constraints are applied can allow exploration programs to be planned more effectively. The termination of seismic programs in January 1991 was met with surprise by many companies who lost the opportunity to acquire important seismic data. Although the terms for timing constraints are routinely provided to applicants in a Letter of Authority from the Public Lands Division, few companies were aware that their operations could be stopped as early as 1 January (and even earlier in some regions). The misunderstanding resulted largely because winter conditions have forced application of the constraints that early only twice during the past decade.

Education can be conducted through both formal and informal means. In-house seminars by environmental staff or consultants can be useful in informing and updating all company departments. It is important to include field staff as well as head-office personnel in those programs. Workshops, such as one currently being planned by the CPA Caribou Steering Committee, can function the same way on an industry-wide scale.

Government agencies may also benefit from cooperative workshops. Many restrictions on exploration and development in caribou range are not considered practicable from an industry perspective. To resolve this type of issue, a planning exercise, involving knowledgeable caribou biologists, AFWD habitat biologists, AFWD headquarters staff, and industry representatives familiar with exploration and development practices, could yield a series of alternative measures acceptable to both wildlife managers and the petroleum sector.

Public forums held by one or more companies in communities near caribou range may be an effective means of involving native groups and the general public.

5.3 Communication

As with education, communication within and among companies is essential. (In some instances, field personnel and head-office staff within the same company may work to cross purposes when confronted with timing or access constraints.) Communication with contractors is also an important consideration.

Government staff should be kept informed of short- and long-term development plans. In many instances, government managers are not approached until a controversy arises. All AFWD habitat biologists that we have spoken with encourage early contact by petroleum companies, and are willing to discuss specific issues during the project planning phase. Understanding the disposition of the land base and the long-range plans of other resource users is crucial. Dialogue with other stakeholders, including the forest industry, native groups, and conservation groups will assist planning during all phases of development.

The development of a common land-based data system on a Geographical Information System (GIS) is recommended to facilitate communication among industry sectors and government. Much of the information important to effective caribou management is related to habitat and the distribution of that habitat on the land. By storing the pertinent information in a digital format that can be quickly and easily updated, range assessments can be performed, planned developments can be overlayed, and impacts identified. A provincial initiative, the Collective Vegetation Inventory (CVI), is currently underway to map vegetation in the province at a scale of 1:20,000. The CVI, in digital format, will become an important component of operational planning by forest companies within FMAs. The CVI will also be a useful base for regional and local caribou habitat mapping programs.

5.4 Cooperation

Above all, cooperation with other petroleum companies, other resource industries, government departments, native groups, and conservation groups is required. The basic format of Standing Committees has not yet been determined. We suggest that this is the most effective vehicle for establishing cooperative relationships. In some areas, working groups such as the one established for the west-central region may be useful. The apolitical atmosphere of the group has allowed open and frank discussion of issues and concerns.

Cooperation can reduce physical impacts through coordinated activity, while allowing more effective information collection, more efficient planning of land access, and lower costs through shared facility development. By pooling funds for data collection, more-effective information can be obtained more efficiently.

6.0 SUMMARY

If companies are truly willing to work with other stakeholders, the goals of information collection, education, communication, and cooperation can be met. The approach we recommend will not solve all conflicts between caribou managers and the petroleum industry. Caribou are sensitive to disturbance, they occur at low densities, and they require large areas for the maintenance of healthy populations. As a result, they are a difficult species to maintain within a multiple land-use environment. No effective management plan can allow unrestricted development and conflicts will inevitably arise.

It is easy for us to urge candid communication and better cooperation; realizing those goals will be difficult. Solutions will not be simple. However, effective operation by the petroleum industry within caribou areas is contingent on a framework for identifying data needs and priorities that involves a long-term, provincial perspective. Only by being better informed, openly communicating and cooperating can a workable solution be achieved.

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THE NEB PIPELINE CROSSING REGULATIONS AND THE ROLE OF THE LAND AGENT IN THIRD PARTY DAMAGE PREVENTION

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From its first version, adopted in the late 1950's, the National Energy Board Act required that anyone wishing to construct any of a long list of facilities across a pipeline required prior permission of the Board. As a result, the Board received between one and two thousand applications annually which were diligently reviewed by Board staff and, for the most part, routinely approved by the Board.

The initial emphasis of this process was focussed on control of right-of-way encroachments, however, very early in the game, the concept of safety and third-party damage prevention started to grow in importance and soon became the principal purpose of the exercise.

The process of requiring formal approval was seen as an opportunity for both parties, the pipeline company and the excavator, to pause and ensure that all appropriate factors had been considered and any foreseeable hazard had been compensated for.

Notwithstanding this "pause for thought", pipeline damages were still occurring. The thought and care that went into the planning stage was being eclipsed by moments of carelessness in the field - carelessness brought on by a lack of knowledge of the hazards involved and how to avoid them or by simple negligence.

Another problem was also recognized. The process of formal Board approval, which ensured that safety concerns were addressed in the planning and design stages, was felt by some to be burdensome in those situations where the job planning and facility design stages were informal or virtually non-existent. The installation of house services such as sewer and water lines, the installation of tile drains or even simple gas distribution or telephone cable installations frequently did not have sufficient scheduling flexibility to accommodate the need for such approvals, unless the need was identified very early in the planning.

In the fall of 1988, the NEB introduced the Pipeline Crossing Regulations, marking a significant change in the approach taken by the Board toward controlling excavation and construction around federal pipelines.

The regulations shifted the emphasis entirely to safety and third party damage prevention. The regulations established that approval of the Board was not required, if the affected pipeline company granted permission for the activity. If the pipeline company refuses permission, the individual can still apply to the Board.

Part I of the regulations established the responsibilities of the excavator or contractor, such as:

- 3 day notice to the pipeline company before starting work;
- no excavation near the pipe until staking is completed;
- no mechanical excavation within 3 metres until the pipe is exposed by hand;
- compliance with any conditions of permission and the instructions of pipeline company inspector;
- calling the pipeline company, if the pipe or its coating is contacted;
- notifying the pipeline company prior to backfilling; and
- ceasing work when ordered by the pipeline company inspector.

Part II of the regulations established the responsibilities of the pipeline company. In addition to the obvious responsibilities of granting permission to the excavator, locating the pipe and providing a certain level of field inspection, the pipeline company was called upon to:

- establish a public awareness program directed to potential excavators and regularly review its effectiveness;
- report to the Board any hazardous events, violations of the regulations or any situation where unsafe practices necessitated the suspension of permission by the pipeline company;
- respond to the excavator within a certain time frame; and
- maintain minimal records of approvals and inspections.

In support of the new regulations, the Board also became more field-oriented with regard to crossings.

Currently, each reported violation of the regulations is followed-up by Board staff with the goal of ensuring that proper steps are taken by the excavator/facility owner in order to prevent a recurrence. As a result, some major utilities have changed the way that they approach pipeline crossings.

Board staff conduct random field inspections of crossing sites. This activity is aimed at creating a clear impression of accountability on the part of the excavator to a regulatory agency. We have been told by pipeline company field staff that this has made their job a lot easier.

Staff regularly discuss with the pipeline companies, their damage prevention and public awareness programs. Suggestions and observations are advanced based on the activities and successes of other companies and an intra-industry exchange is encouraged.

The Board also takes initiatives which are appropriate for a regulatory agency in order to advance the cause of third-party damage prevention. These initiatives range from the publishing and updating of an excavators' guide to presentations such as this, to assisting and encouraging the initiatives of others, such as the development of one-call systems.

The change in regulatory approach appears to be making a more significant contribution to safety than the former regulatory regime, while requiring less than one-third of the manpower resources.

Studies coming out of the United States tend to indicate that an effective regulatory regime does make a difference in third-party damage prevention. A study done in the New England states, which have adopted virtually the same regulation, indicated a marked statistical difference in third-party damage between states which enforce damage prevention regulations versus those which don't.

Regulatory initiatives are only one small part of the group of activities which constitute third-party damage prevention.

When one thinks of damage prevention initiatives, a number of ideas come to mind depending on your background and experience.

- One-call systems, where the excavator informs all members of the system, simultaneously, of his intent to dig and of related details. Some one-call systems also feed back appointment times and details to the excavators.

- Line markers and signage, which inform the public of the nearby presence of buried pipe, who to contact, and sometimes, the nature of the product being carried.

- Advertising, in a variety of forms, which let anyone and everyone know of the dangers of uncontrolled excavation.

- Promotional items, ranging from general distribution items like pens to specific audience items like pocket reference manuals, which remind the recipient of the pipeline company or of a short effective message.

Presentations, display booths, liaison visits, safety awards, ground and air surveillance; the list of damage prevention initiatives is almost limitless. There is, however, one commonality shared by these initiatives. The purpose of these initiatives is to find out the intent of the third-party and to inform the third-party of the presence of the pipeline and the resulting responsibilities. This purpose can be summed up in one word - communication. The other third-party damage initiatives, such as ground or air surveillance, come into play when the first line of defense, communication, has broken down.

It is interesting to note how often "communication" is identified to be the source of both systemic and day-to-day problems found in all organizations. People, who in the past would carry such titles as Public Relations Director, now are called Communications Director. Internal communication has reached a level of science where communication specialists are part of the management consulting industry.

Within the pipeline industry, there have always been individuals whose job demanded a high level of communication skills. Those individuals, of course, are land agents or right-of-way agents. As such, right-of-way agents can be part of the solution to the problem of reducing third-party damage.

For those who are not involved in pipeline crossings on a regular basis, it becomes difficult to make a meaningful contribution to third-party damage prevention; difficult but possible. The first step is to find out what your company policies and practices respecting third-party damage prevention are, and seek out ways in which you can assist. Identify those parties with which you have regular contact and to whom the corporate program is focussed or should be focussed. Take the initiative to integrate the company's damage prevention messages into your routine contacts with these people. Remember the problem is communication and that is your speciality. As a communication specialist, you can make a valid contribution to the damage prevention with little effort and with little or no distraction from your principal responsibilities.

For those who are involved in pipeline crossings on a regular basis, there are several initiatives you can take to contribute to third-party damage prevention. If you are crossing a foreign pipeline or if you are being crossed, the emphasis shifts but the message is the same. Let us look at it from the perspective of the company doing the crossing. If you are on the other side of the fence, simply ensure, through encouragement and follow-up, that your fellow right-of-way agent in the other company is undertaking these initiatives. Remember, if you have a stake in the project, you have a stake in the safety of the project.

Let's discuss the role of the right-of-way agent in the chain of safety. A chain where the last link is the most vulnerable - the man in the field, and the first link is the right-of-way agent - the person who can set the tone of safety for the entire project.

When you approach the pipeline company for permission to cross, they will probably ask for technical details regarding design and construction methodology. The information you give them is reviewed by the pipeline company in order to identify potential problems. They may come back to you and ask for changes in design or in construction technique. When they grant permission, they will probably have some conditions they would like followed in the field.

This entire activity parallels the process that is of principal interest to you as a right-of-way agent. Your goal is to obtain an encroachment agreement which will give your company or client a legal right on that easement and, in the case of federal pipelines, to obtain the permission necessary to fulfill your obligations under law. Those are your principal goals, but I would like to suggest that if you want to do a professional job, in the best interests of all parties involved, you should consider going one step further. You should consider your role as a link in that chain of safety that I mentioned. An important link which if properly addressed, could silently save lives.

You are the first person and sometimes the only person that the other pipeline company has contact with during the planning phase of your company's project. To the pipeline company, therefore, you are your company. You can be instrumental in eliminating many of the causes of pipeline damage. Here is how.

First, ensure that the design submitted to the pipeline company truly reflects the work that will be done. If the design and proposed construction techniques are to be properly examined for potential problems, the design should be a final design, not a conceptual design. It should accurately reflect what is going to be done and should never conveniently omit reference to an area of potential concern. Yes, pointing out potential problems will cause some delay in the approval process. By dealing with the issue up front, in an open and constructive manner, the delay will be short. Conversely, a fast, convenient approval may introduce problems in the field which take ages to resolve or worse, endanger your fellow employees. The best way to get a good design is to talk with the designer and impress upon him or her the safety dimensions to that specific phase of the project. If you are not successful in getting the message across, then seek help.

Second, ensure that all messages are delivered to the right people. The design drawing that was reviewed and sometimes revised to contain warnings and instructions should not be filed away with all the approval documentation. It should end up in the field at the time of construction. Check your company's post-approval procedures to see that will happen. If you can't change your company procedures, find the time to deliver the message to the field yourself. Visit the site; eventually, both the backhoe operator and management will get the message.

Third, ensure that the construction crew knows how to safely construct around foreign pipelines. It is in the ditch that accidents occur. The construction related conditions to the approval and the construction standards found in the Pipeline Crossing Regulations must be communicated to the field. This is especially true when using any contractor but especially true for non-pipeline contractors. Accidents can occur due to negligence. Accidents can also occur due to people making an honest effort but not understanding the hazards or not being aware of the subtle complexities of the project. The person on site has a need to know. They should know the special conditions and the construction practices found in the regulations. It is unfair to them if they are not told that these practices are not a guideline but a law.

You become aware of these special conditions and of the regulations when obtaining the necessary approvals. Unless you make a special effort, you may be the only person in the company who is aware. Remember, you are the first link; focus on the last link in the chain. Just as you did with the design drawing, ensure that all messages are delivered to the right people.

Fourth, assume safety as a part of your responsibilities. Not just safety of pipeline crossings, but safety as a whole. Look for the opportunity to enhance safety in every activity you do. When handled with tact and with the techniques of conflict management that are normally part of the skills of a right-of-way agent, there is no problem you can't tackle. "Safety is everyone's job", should be more than a cliché to the right-of-way agent involved in pipeline and utility coordination.

Remember the chain of safety. You are the first link, but with your effective involvement, the whole chain can be made stronger and safer. Don't let the first link be the weakest link. First, ensure a credible design. Second, get the approved design drawing into the field. Third, make the construction crew aware of what they are dealing with, and fourth, take the initiative on safety.

Out of sight, out of mind, is more than just an old adage. Pipelines are silent and non-visible. Make them visible but keep them silent.

Volume

2

CANADIAN PETROLEUM ASSOCIATION

1991 PIPELINE CONFERENCE
"PIPELINES IN A CHANGING ENVIRONMENT"
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NITROGEN PURGE OF A 30 INCH CRUDE OIL PIPELINE

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Nitrogen Purge of a 30 Inch Crude Oil Pipeline.

Introduction

During September and October of 1990 Trans Mountain Pipe Line undertook the task of purging crude oil from two 80 kilometre loops of NPS 30 pipeline using nitrogen propelled pigs. The loops run parallel to the NPS 24 Trans Mountain mainline from Edson to Hinton in Alberta and from Darfield to Kamloops in B.C. These loops traverse a tremendous variety of terrain including numerous mountainous areas. Although purging a liquid filled pipeline with N2 is not a particularly innovative procedure, the terrain the Trans Mountain line traverses provided several major challenges which combined to make the project unique.

Both of the loops had been dormant since the mid 1980's and had each been shut in with a full line fill of crude oil. The purges were performed to void the lines of oil to enable future planned rehabilitation programs of the dormant lines and to return approximately 70,000 cubic metres of oil to Trans Mountain's shippers to reduce their inventory costs. The large volume of oil in the lines made the prospect of conventional drain down techniques undesirable and nitrogen purging was chosen as the most practical method of draining the lines.

The job would entail pushing a train composed of two high separation batch pigs through the line using compressed nitrogen gas. The advantages of such an operation are the high efficiency of the displacement which leaves little residual oil and the inerting qualities of nitrogen which protect the line from corrosion and add a factor of safety to the dormant line.

Due to its topography, the Darfield to Kamloops loop became the most difficult challenge. The loop runs for 80.95 kilometres between Trans Mountain Km 741.46 and Km 822.41. The end point elevations are 380 metres above sea level at Darfield Station and 750 metres above sea level at Kamloops Station tankage. The line is characterised by a profile containing several steep elevation rises. The most notable are elevation changes of 410 m over three kilometres, 375 m over four kilometres and 325 m over 2 kilometres. Figure 1 shows a profile of the pipeline. Other items of interest regarding the loop are the valves at Km 779, Km 818 and Km 819.

Technical Alternatives

During the planning phase of the project, several options were examined in an effort to find the plan which would minimize cost, nitrogen consumption and pipeline down time. It was most important to minimize nitrogen consumption since the nearest suitable source of product was Edmonton, Alberta, a distance of nearly 800 kilometres. Since a major portion of nitrogen cost is distribution and transportation cost, the easiest way to minimize cost was to minimize consumption. The third criterion of minimizing system down time was necessitated by the relatively small amount of available tankage at Kamloops Station, approximately 9,500 cubic metres. This meant the available tankage could not contain more than about one quarter of the line fill and thus several mainline shut downs would be required to enable batches to be pumped from tankage. In total, four different alternatives were considered for the purge to find the most feasible and economic solution.

The first alternative was to displace the entire line simply by installing enough nitrogen gas behind the pig to overcome any hydrostatic head encountered. The severe line profile of the area, particularly the difference between the starting and ending points, can produce crude oil heads in excess of 3500 kPag. Therefore a nitrogen pressure of approximately 3700 kPag, including pig differential, would be required for nearly the entire length of the pipeline loop. The loop has a fluid volume of approximately 35,000 cubic metres which would require a purge volume of in excess of 1.35 million standard cubic metres of nitrogen. Contact with industry sources indicated such volumes would be difficult to supply over a short period of time at such a distance from the source. At this point it was determined the feasibility of the project depended upon finding a purge method which would substantially reduce the nitrogen volume required.

Two courses were investigated to accomplish this objective. The first was to make better use of a portion of the nitrogen by recycling it and the second was to reduce nitrogen pressures by reducing the hydrostatic forces opposing the pigs.

To recycle the nitrogen it was proposed to displace the line from Km 741.46 to the mainline valve at Km 779 in a conventional fashion using a pig train propelled by high pressure nitrogen injected at Darfield Station. Once the pigs had passed the valve it would be closed and a compressor installed on the valve bypass connections would be used to recompress the nitrogen around the valve to a point where the compressor would lose suction. At that point a nitrogen pumper would be connected to the down stream side of the valve and extra nitrogen would be injected as needed. The limiting factor in this scenario was the low end suction limits of the compressor which resided in the 1000 kPag range. A substantial benefit was calculated and the total nitrogen consumption was forecast at 860,000 cubic metres, a savings of approximately 490,000 cubic metres.

The second tactic investigated was the reduction of hydrostatic forces in front of the pigs. To accomplish this it was determined that oil had to be pumped out of the line at the bottom of the large profile rises downstream of the pig train. This would reduce the height of the oil column in front of the pig and the corresponding hydrostatic pressures. The result would be substantially reduced nitrogen pressure and volume requirements. The most convenient disposition of the oil was to pump it from the NPS 30 loop across to the adjacent NPS 24 Trans Mountain mainline. Initially it was thought pump across sites would be required at four locations, specifically, just before each of the major profile changes at kilometres 754, 772, 808 and 819. It was later determined that at least 500,000 cubic metres of nitrogen would be required to complete the displacement under this scheme and that this volume was sufficient to displace the line to Km 778 against full hydrostatic head. The nitrogen would then expand as oil was removed from the pump across sites at Km 808 and 819. This enabled the first two pumping sites at Km 754 and 772 to be eliminated. It was estimated this method would consume approximately 580,000 cubic metres of nitrogen.

Finally, a variation of the preceding plan was developed. The purge would commence as previously explained, with the pigs being propelled to Km 778 by nitrogen pressure alone. Again, two oil pumping sites would be set up, but at Km 805 and Km 818, where oil would then be transferred from the NPS 30 line to the NPS 24 mainline. As the oil transferred across at the Km 818 site, a bi-directional pig would be launched from Kamloops Station at Km 822, the loop end point, and propelled with nitrogen back towards the pigs coming from Darfield. Nitrogen injection would be controlled from Kamloops to enable the pumping site at Km 805 to be bracketed from either side by the pigs moving in opposing directions. As much oil as possible would be pumped from between the pigs until suction conditions degenerated to where it was no longer practical. Nitrogen would then be vented from Kamloops Station enabling all three pigs to move from Km 805 to Kamloops Station with little or no extra nitrogen addition from the upstream end of the loop. This method would also alleviate concerns over the pigs running unopposed should they encounter a section of line voided of oil. A charge of nitrogen on the downstream side of the pigs would ensure a controllable pressure differential across the pigs. The total forecast nitrogen consumption was 535,000 cubic metres.

This plan predicted the job would be completed using nearly 65 percent less nitrogen than a conventional straight through purge. Contracts were let for the supply of nitrogen and pumping equipment and Nowsco Well Services Ltd of Calgary, Alberta was awarded the work. The nitrogen vaporization and pumping was performed by three SP-6000 tractor trailer pumper units, each capable of 170 m3/min at a maximum pump discharge pressure of 68,900 kPa. The crude oil pumping was performed at Km 805 by three VT-1200 Triplex reciprocating frac pumper units, each capable of 4.0 m3/min of crude oil. The oil pumping was performed at Km 818 by skid mounted multi-stage centrifugal units capable of 2.6 m3/min and owned by Trans Mountain. All job coordination, supervision, engineering and manpower was provided by Trans Mountain.

To enable a continuous supply of nitrogen, Nowsco imported on site portable storage tanks which held approximately 320,000 cubic metres of nitrogen in liquid form. Some of this tankage included semi trailer tankers which were emptied first and then dispatched to Edmonton for more product while the stationary storage was drawn down.

The decision to use the frac pumpers was necessitated by the relatively high pumping heads. The pumps were required to pump from low suction pressures and overcome passing mainline pressure of up to 4200 kPag in the operating NPS 24 line. The requirement to pump approximately 20,000 cubic metres of oil inside of 72 hours meant flow rates of nearly 300 m3/hr had to be maintained. These flow rates and pressures meant only large reciprocating pumps would suffice since the portable multi-stage centrifugal pumps available did not have the required capacity.

Technical Problems and Considerations

The project also presented several interesting operational and control problems. The first problem was one of differential pressure control of a pig train at an oil/gas interface. This problem is best explained by considering the hydraulics encountered as the pigs progressed up or down pipeline profile variations. Referring again to Figure 1, a pig progressing from Km 741 would require a nitrogen pressure of approximately 3700 kPag due to the opposing hydrostatic head generated by the first major ascension between Km 754 to 758. Progressing the pigs the 13 kilometres to Km 754 would install about 216,000 cubic metres of nitrogen behind them. Across level ground the pig is kept moving by a slight positive differential. However as the pig begins to ascend uphill it experiences progressively less opposing hydrostatic head as the height of the oil column in front of it decreases. The large volume of high pressure nitrogen behind the pig causes the gas pressure to decrease much more slowly as the pig moves along. The net effect is a rapidly increasing differential pressure across the pig and a corresponding increase in net propulsion force.

An NPS 30 pig has a face area of 675 square inches. Therefore a pressure differential of one psi produces 675 pounds of force. The ascension from Km 754 to 758 resulted in a static differential increase of over 2800 kPag or over 400 psi. The result was a potential driving force of some 135 tons. Naturally once the pigs were moved to the base of a major rise, all nitrogen additions could be stopped and the stored potential energy in the nitrogen moved the pigs along until the pigs crested the hill top and began to descend back down into a valley, where they would encounter increasing hydrostatic head and decelerate until hydrostatic forces balanced those of the expanding nitrogen gas.

As the pigs moved in the uphill direction they would accelerate dramatically causing substantial increases in flow rate. At first it was thought the flow should be controlled by routing it through a control valve at Kamloops Station but it became readily apparent this procedure would present a more serious problem.

Considering the previous example, as the pigs moved towards the apex of the profile rise the propelling nitrogen pressure would fall to approximately 2800 kPag but the pressures downstream of the high point would be equal to hydrostatic fluid pressure plus the pressure of the nitrogen propellant. Therefore under static conditions the lowest points could experience pressures of more than 6100 kPag. The limiting MAOP in these areas ranges from 6400 to 4900 kPag, depending upon wall thickness. Thus flow restriction could result in excessive system pressure rises which could damage piping and would certainly activate surge relief valves, causing the filling of surge relief tankage at Km 818 and at Kamloops Station.

The NPS 30 loop was constructed with higher wall thicknesses at the upstream end and sections of lighter wall further downstream to accommodate normal line losses. After reviewing the MAOP in each of the low sections the area of greatest concern became the pipe between Km 802 to 807 where the MAOP is as low as 4900 kpag. It was concluded the safest way to handle the problem was to restrict flow rates as little as possible, and take advantage of the substantial pressure drop in a line flowing at high velocity. The line losses at this point would include the pressure drop of at least 46 kilometres of pipeline.

To accommodate the high flow rates the NPS 24 mainline into Kamloops Station was shut down and tankage pumped to low levels to keep the line in operation downstream of Kamloops Station. Station valving was aligned directing flow into the main station suction header from tankage enabling as much oil as possible to flow through the operating pump station while any excess could flow to tankage.

Tracking of the pigs was accomplished by installing battery operated radio transmitters inside the pig bodies and following the progress of the units with hand held receivers on the surface. This job was contracted out to a specialty service and proved invaluable in charting job progress. The tracking was most effective when the receivers were set up at predetermined checkpoints to wait for the pigs to pass by and then moved along to the next checkpoint.

Job Progress, Problems and Solutions

The purge began on the morning of September 24, 1990. The first pig was successfully launched with nitrogen and pushed approximately 300 metres downstream prior to the launch of the second pig. A slight problem was encountered with the launch of the second pig due to a small nitrogen leak past the NPS 30 sending barrel isolation valve. This leak generated just enough back pressure to push the pig back out of the barrel transition, making a nitrogen launch nearly impossible. This problem was solved by sealing the trap, opening the NPS 30 isolating valve and flowing a small amount of crude oil through the barrel kicker valve. Once the pig was passed the transition of the barrel, crude flow was discontinued and nitrogen flow was commenced.

The initial push out of Darfield Station required between 3500 and 3700 kPag of nitrogen which was pumped at a rate sufficient to produce a crude flow into Kamloops Station of between 300 and 400 m3/hr, This corresponded to a pig speed of about 0.75 km/hr. The variations in flow and pressure were caused by the undulations in pipeline profile as previously explained. Approximately 11 hours later the pig train reached the first major ascension where flow into Kamloops Station began to significantly increase as expected. At this point nitrogen injection was stopped and the installed gas allowed to expand.

Initially all flow into Kamloops Station was directed through a suction side control valve set to allow a maximum flow of 1000 m3/hr. The flow climbed to 1000 m3/hr where it was held until a back pressure of 850 kPag and rising was recorded at Kamloops Station due to the force generated by the nitrogen gas in conjunction with hydraulic head. Since the suction side relief setting at Kamloops Station is 1000 kPag the decision was made to bypass the control valve to reduce the station back pressure by maximizing flow. As previously mentioned, the NPS 24 mainline upstream of Kamloops was now shut down with the running pumps at Kamloops, receiving a blended suction flow from the NPS 30 loop and station tankage.

The maximum flow rate at Kamloops Station through the NPS 24 mainline is 1750 m3/hr, a rate seldom achieved due to back pressure conditions downstream of the station. Flows up to 1500 m3/hr are typically experienced. Upon bypassing the incoming control valve the flow through the station immediately jumped to 1650 m3/hr and the flow from tankage reversed to the point where an estimated 1400 m3/hr were flowing to tankage. Thus the total flow into the station was over 3000 m3/hr with no external application of power. This situation continued for 2.5 hours until the pig train began to experience increasing hydrostatic head downstream of the local high point. The pigs came to rest downstream of the high point near Km 767, some 13 kilometres past the point where nitrogen injection had ceased.

The next major profile rise occurred from Km 772 to 774, a vertical rise of 325 metres. Referring again to Figure 1, it can be seen that to push the pigs to the bottom of the low point at Km 772 the entire hydrostatic head from the high point at Km 821.5 would have to be overcome. This would require pressurizing the upstream pipeline to 3300 kPag all the way from Darfield Station, some 30.5 kilometres of pipe. The installed energy in the gas would cause tremendous flows as the pigs carried on up the steep rise. To minimize nitrogen energy it was decided to close the NPS 30 mainline valve at Km 818 and pump around it with a 325 m3/hr single stage centrifugal pump. This operation effectively decreased the head downstream of the pig train to that of the immediate elevation high point at Km 774. Thus only 2700 kPag of nitrogen pressure was required to drive the pigs to the valley bottom. Once the pigs passed the transition point at Km 772 and flows began to increase, the pump at Km 818 was shut down and the mainline valve was opened. Once again the mainline upstream of Kamloops was shut down and the valving aligned to allow maximum flow. The opened valve at Km 818 allowed more hydrostatic head to oppose the pigs than in the previous case and the lower installed nitrogen energy combined to limit the flow of oil into Kamloops Station to 1950 m3/hr.

In this instance the peak flows lasted for only 30 minutes and quickly became static once the peak of the elevation rise had been traversed. The relatively short duration of the peak flows was due to the difference in elevation gradient between the two cases. In the first case the elevation gradient downstream of the high point was about -21 m/km. This meant the pigs were able to travel 9 kilometres past the peak before the pipeline elevation drop enough to generate enough hydrostatic forces to stop movement. In the second instance, the downstream elevation gradient was -300 m/km thus restricting the pigs to only 0.5 kilometres of travel past the peak of the high point.

During both of these operations personnel were stationed at Km 779 and Km 808 to monitor mainline pressures. The highest pressures recorded were 4600 kPag at Km 779 and 3900 kPag at Km 808, both well under established operating limits. The maximum back pressure recorded at Kamloops Station during full flow was 410 kPag. There were no incidents of mainline relief during any of these operations. To this point approximately 14,500 cubic metres of oil had been displaced into Kamloops Station.

With the pigs now downstream of Km 776 the hydraulic pump across operations were now set to begin as was the launching operation of the bi-directional pig from Kamloops Station. The pumping operations were begun from the NPS 30 line across to the NPS 24 line at Km 805 and Km 818. It should be noted a pumping site at Km 808 would have been more efficient from a hydraulic point of view but unfortunately this is a populated area, so the site at Km 805 was chosen to avoid operating heavy machinery in such a location. At both locations the pumps were connected to the mainline with steel piping as is customary. However, it became immediately apparent at the Km 805 site that such an arrangement would not be acceptable.

The three reciprocating frac pumpers operating in unison produced heavy pulsations at the mainline connections and the operation was immediately shut down by on site personnel. The problem was partially rectified by installing a 4 metre length of 7000 kPa, NPS 4 rubber hose as the final connection to the mainline to allow more freedom for piping movement.

To reduce the pulsations from the pumping units two pulsation bottles were borrowed from some old Trans Mountain reciprocating draindown pumps. The bottles were installed on top of Chicksan tees in the pumper discharge line and were charged with an appropriate amount of nitrogen gas from high pressure cylinders. The results were excellent with the pulsations being virtually eliminated, enabling the equipment to operate at an average flow rate of 300 m3/hr.

During this time the bi-directional pig was loaded into the receiving barrel at Kamloops Station and a launch attempted. However, a series of events combined to render this portion of the project unsuccessful. Upon loading the pig it was discovered the third and last pig tracking transmitter had malfunctioned and was no longer operable. It was decided knowing the exact location of this pig would not be as critical as the other pig train and that it could be sufficiently tracked by monitoring pressures and nitrogen volumes to determine its approximate location.

The launch of a pig with nitrogen is characterised by a build up of pressure behind the pig until enough differential is achieved to overcome the static friction of the cups and initiate movement. At this time the nitrogen pressure drops a few hundred kPa and remains constant as the pig travels along. During the launch of the bi-directional pig however, the rubber carrying disks failed forward allowing the nitrogen to bypass the pig leaving it lodged in the barrel. The failure of the pig to launch was not detected immediately for three primary reasons. First of all, due to the failure of the pig tracking radio transmitter there was no external indication of the situation. Second, the characteristic pressurization and subsequent pressure drop as the rubbers failed gave the impression the pig had indeed launched. The third factor was one which was due primarily to the topographical profile of the line upstream of Kamloops Station.

Immediately upstream of the station is a small valley, then a slight hill at Km 821.5 and then a steep drop from Km 821.5 down to Km 819. This drop of 410 metres in 2.5 kilometres is very steep and allowed the bypassed nitrogen to act as a piston on top of the oil in the pipe, thus pushing it to the valley bottom as if there were a pig at the oil gas interface. This was further confirmed by a flow of displaced oil, in the upstream direction, over the high point at Km 813 which caused a noticeable hydrostatic pressure rise at the Km 805 pumping site. When the oil gas interface reached the bottom of the hill the nitrogen moved quickly across the valley and up the hill on the other side. The speed with which this part of the process took place was surprising, and the decision was made to shut down the nitrogen injection from Kamloops. At this time the pig trap was depressured and the pig discovered in the barrel.

There was now a serious problem since not all of the oil had been swept from the valley from Km 821.5 back to Km 813 and the remaining oil was now mixed with approximately 50,000 cubic metres of nitrogen gas making any pumping operations extremely difficult. The scope of the job had now changed and new solutions were required to complete the job while still minimizing nitrogen consumption. The first action was to allow time for the oil and nitrogen to separate in the pipeline and then vent off as much gas as possible. Venting operations were performed at Kamloops Station and at Km 818. Surprisingly, once venting had been completed it was discovered no pressure at all existed in the valley bottom at Km 818. The pipeline was full of oil across the flat valley bottom but contained no oil on the hills at either end. Therefore a substantial amount of oil had been swept over the high point at Km 813 and would be handled by the pumps at Km 805.

For the next two days pumping operations continued at Km 805 until the upstream pig train had progressed to within a kilometre. At this point nitrogen gas which had leaked past the advancing pigs made its way into the pumping site and began to play havoc with suction equipment. Pumping operations were terminated due to safety concerns and the equipment was released. Approximately 14,000 cubic metres of oil were pumped from this site by the frac pumping equipment.

The pigs were now four Km short of the next major elevation rise at Km 808. To coax the pigs to this point, where it was anticipated they would continue on unassisted, a small pump across operation was carried out at Km 808.25 using an 80 m3/hr multistage centrifugal pump operating between two sample fittings. This operation continued for 24 hours until the pigs reached the hill bottom at Km 808 and once again bypassing nitrogen forced the shut down of the pumping equipment. At this point the pigs remained static and the decision was made to close the nearest upstream valve at Km 779 and inject enough nitrogen behind the pigs to initiate movement up the hill at Km 808. The nitrogen pressure upstream of the pigs was now at 1100 kPag and it was estimated 1400 kPag would be required to move the pigs.

Nitrogen was injected at Km 805 until the pressure upstream of the pigs reached 2000 kPag and still the pigs remained static at Km 808. Nitrogen injection was stopped to allow re-evaluation of the problem and determine why such a substantial pressure would not move the pigs. Vents were then hot tapped into the line at the high points at Km 813 and Km 809, just downstream of the pig train. At Km 813 there was no pressure but at Km 809 a 600 kPag pocket of nitrogen was found. The nitrogen which had originally bypassed the pig train had migrated to the high point and was now exerting force on the oil at the upstream side of a swale located near Km 811. This in turn forced oil up the hill on the downstream side of the swale creating a balancing hydrostatic pressure. In essence, the two hills from Km 808 to 809 and Km 811 to 813 had been hydraulically connected to cause a higher static pressure to be exerted at Km 808 than should have been produced by the first hill alone.

The nitrogen pocket at Km 809 was vented away leaving 450 kPag of crude oil pressure. A small extra amount of nitrogen was injected at Km 805 until the pigs began to move. Pressure now began to accumulate in the voided pipe at the Km 813 high point as the advancing crude decreased the voided volume. This pressure was immediately vented away and the pigs advanced due to nitrogen expansion past the Km 813 high point. The advancing oil now accumulated in the next valley leaving a static pressure of 3200 kPag.

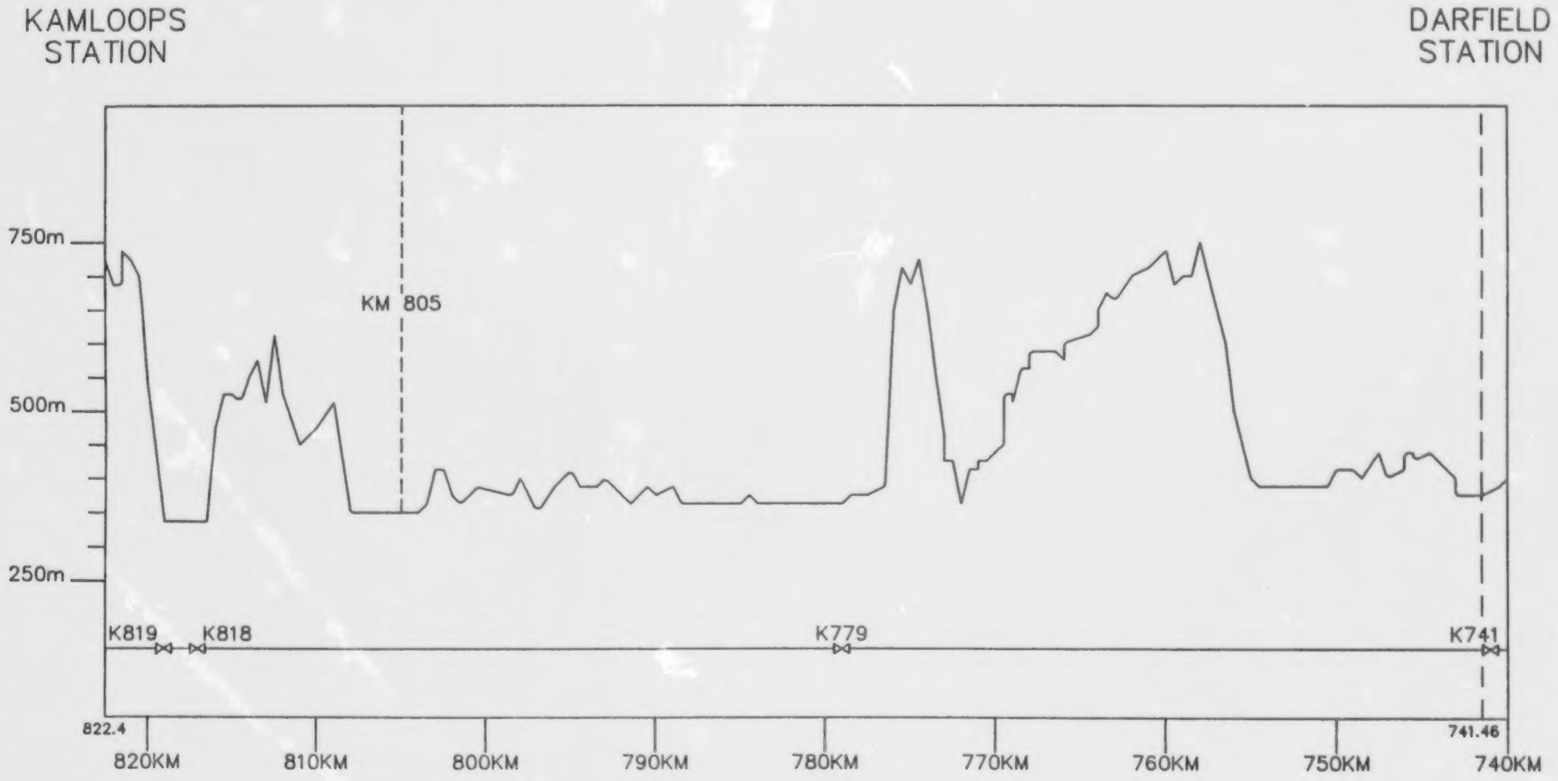
The next chore was to advance the pigs through the mainline valve at Km 818 so the valve could be closed and the pigs pushed into Kamloops Station with nitrogen. It was critical the pigs be moved past this valve prior to nitrogen injection or the pipeline would have to be pressured up all the way back to the valve at Km 779. Such action would consume a tremendous extra amount of nitrogen and practically negate any conservation measures successful to this point. To accomplish this task, the valve at Km 818 was closed and pumped around until the crude oil volume upstream of the valve was reduced to an amount which could be accommodated by the relief tankage existing at the Km 818 site. This procedure emptied most of the crude from the upstream side of the valve at which point bypassed nitrogen began flowing to tankage. A liquid/gas separator was then connected to the line to remove the nitrogen from in front of the pigs.

Once the pigs were sufficiently close to the Km 818 valve, the valve at Km 819 was closed to isolate the downstream pressure. The Km 818 valve was then opened and one tank truck load of oil was removed from a vent 200 metres downstream. This procedure moved the pigs through the valve at which point it was closed. Nitrogen was then injected on the downstream side of the valve to push the pigs into Kamloops Station and complete the purge. 4200 kPag of nitrogen pressure was required instead of an expected 3500 kPag due to another pressurized nitrogen pocket at the Km 821.5 high point. This pocket was not vented due to the relatively small line volume between Km 818 and the hill bottom at Km 819.

Conclusion

In total, 665,000 cubic metres of nitrogen were consumed by the purge. While in excess of the predicted 535,000 cubic metres, the consumption was still less than half of the 1.35 million cubic metres which a conventional straight push purge would have consumed. A total of 34,826 cubic metres of oil out of a possible 35,164 was recovered during the operation, an efficiency of over 99 percent.

Purging large sections of big inch crude oil pipeline in rugged, mountainous terrain is not common practise nor is it inexpensive. The project included several physical phenomena which combined to make the job a difficult challenge. But the operation's return of a substantial volume of crude to the shippers and rendering of the line empty and safe for future rehabilitation purposes made the project a technical success.



TRANS MOUNTAIN PIPELINE NPS 30" LOOP
DARFIELD TO KAMLOOPS
FIGURE 1

TRANS MOUNTAIN PIPE LINE COMPANY LTD.

ULTRA-HIGH PRESSURE ARCTIC NATURAL GAS PIPELINES

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Calgary, Alberta
May 14, 15 and 16, 1991

SUMMARY

Ultra-high pressure gas pipelines operate at pressures greater than 15 MPa. They can carry large quantities of intermediate weight hydrocarbons such as ethane, propane and butane in a single dense phase. Diameters are smaller than conventional high pressure gas pipelines carrying the same quantity of gas but walls are thicker. Smaller diameters make them more flexible and thicker walls make them more robust. They are therefore well suited to Arctic environments where frost heave and thaw settlement are concerns. In addition, they flow at almost constant temperature, more like an oil line than a gas line, so that frost heave and thaw settlement are minimized. Physical comparisons show they use a similar quantity of steel as an equivalent conventional pressure pipeline with a separate gas liquids line. It is therefore concluded that ultra-high pressure pipelines deserve serious consideration for transporting natural gas from the Arctic.

INTRODUCTION

During the last 20 years several groups have proposed buried pipelines and oil tanker systems to transport oil and gas from the Canadian Arctic. Exploratory drilling has found significant reserves of natural gas. The Geological Survey of Canada estimates that 330 x 10^9 m^3 (11.7 tcf) of natural gas has been found so far in the Mackenzie Delta/Beaufort Sea and there is expectation that a further 1600 x 10^9 m^3 remains undiscovered.[1]

Gulf Canada Resources has estimated that 30 percent of their natural gas reserves are made up of associated and solution gases.[1] These gases usually contain intermediate weight hydrocarbons such as ethane, propane and butane. These components are difficult to carry in significant quantities at normal pipeline pressures because of vapour problems if they are included in the oil stream, and liquids problems if they are included in the gas stream. Some proposals have called for the construction of a separate gas liquids line as well as schemes to burn some of the gas liquids for fuel in the Arctic.

Ultra-high pressure pipelines can carry large quantities of intermediate weight hydrocarbons in a single phase. They operate at pressures greater than 15 MPa, which is almost twice the pressure normally used for the long-distance transportation of natural gas. The concept has been developed in an attempt to satisfy environmental, engineering and economic constraints of Arctic regions. It arose out of earlier work on the dense phase transmission of natural gas at conventional pressures and at temperatures in the vicinity of -80°C.[2] This time dense phase transmission is achieved by operating at ultra-high pressures rather than very low temperatures, and the advantages of carrying richer gases are explored in greater depth.

GAS COMPOSITIONS

Pipeline proposals for transporting natural gas from the Canadian Arctic have envisaged operation at temperatures just below freezing to prevent high ice content permafrost through which the pipelines must pass from melting and causing surface erosion as well as differential movements that could cause pipeline failures.[3] Operation at sub-freezing temperatures and at conventional pipeline pressures requires relatively lean gases to prevent liquids from forming and causing troublesome two-phase flow in the pipeline. Proposals have envisaged pipeline gases composed almost entirely of methane with only small amounts of ethane and practically no quantities of propane or heavier components. Hydrocarbon dew points around -25°C at station suction pressure have been typical.

A recent application to the National Energy Board of Canada for a natural gas export licence[4] provides a lean gas composition that would be suitable for transportation in a conventional high pressure gas pipeline from the Canadian Arctic, along a corridor up the Mackenzie Valley to connect with the existing pipeline system in Alberta. The lean gas composition (Mixture 1) is given on Table 1 together with a gas liquids composition (Mixture 5) made up of ethane, propane and butane which can not be carried in the lean gas pipeline or by crude oil pipeline or tanker. In determining the composition of Mixture 5 it was assumed that a cut would be made in the middle of the pentanes, with components heavier than pentane going to a crude oil pipeline or tanker and components lighter than pentane going to the ultra-high pressure gas pipeline.

Precise gas compositions will remain a matter for speculation until pipelines are actually built and reservoirs are fully explored, but at this time these two compositions are representative of hydrocarbon streams that would be available from the Arctic. Mixtures of the two streams are also given in Table 1. The exact ratio of the two streams that will be obtained is unknown at this time and depends not only on the composition of gas and oil wells in the Arctic, some of which have not yet been discovered, but on the ratio of natural gas to crude oil that ultimately will be produced.

Component	Mixture 1	Mixture 2	Mixture 3	Mixture 4	Mixture 5
Mixture 1	100	90	75	50	0
Mixture 5	0	10	25	50	100
Methane	92.8910	83.7709	70.0903	47.2905	1.6900
Ethane	3.2280	3.4966	3.8995	4.5710	5.9140
Propane	1.1240	3.0816	6.0180	10.9120	20.7000
i-Butane	0.2390	1.9821	4.5968	8.9545	17.6700
n-Butane	0.3200	3.1555	7.4088	14.4975	28.6750
i-Pentane	0.0760	1.2076	2.9050	5.7340	11.3920
n-Pentane	0.0500	1.0787	2.6218	5.1935	10.3370
Hexane	0.0370	0.3437	0.8038	1.5705	3.1040
Heptane	0.0110	0.0543	0.1193	0.2275	0.4440
Octane	0.0040	0.0099	0.0188	0.0335	0.0630
Nonane	0.0010	0.0019	0.0033	0.0055	0.0100
Decane	0.0000	0.0001	0.0003	0.0005	0.0010
Nitrogen	0.5910	0.5319	0.4433	0.2955	0.0000
Carbon Dioxide	1.4280	1.2852	1.0710	0.7140	0.0000
Total	100.0000	100.0000	100.0000	100.0000	100.0000
Molecular Weight	17.6273	21.5645	27.4702	37.3131	56.9989

Table 1: Fluid compositions (mole-percent) and molecular weights

PROPERTIES

Phase envelopes for the five mixtures are shown on Figure 1. The familial behaviour of light and intermediate weight hydrocarbons is easily recognized. The cricondentherms of the mixtures range from -20°C to +150°C and the cricondenbars range from 4.5 MPa to 14 MPa. At conventional pipeline pressures in the range 6 to 10 MPa and at sub-freezing temperatures, Mixture 1 is transported as a gas and Mixture 5 is transported as a liquid. At 0°C Mixtures 2 and 3 can be successfully transported in a single phase only at pressures above 14 MPa. Mixture 4 can be transported in a single phase only at pressures above 9 MPa. An ultra-high pressure natural gas pipeline can therefore provide a means of transporting almost any practical quantity of ethane, propane and butane in a single dense phase.

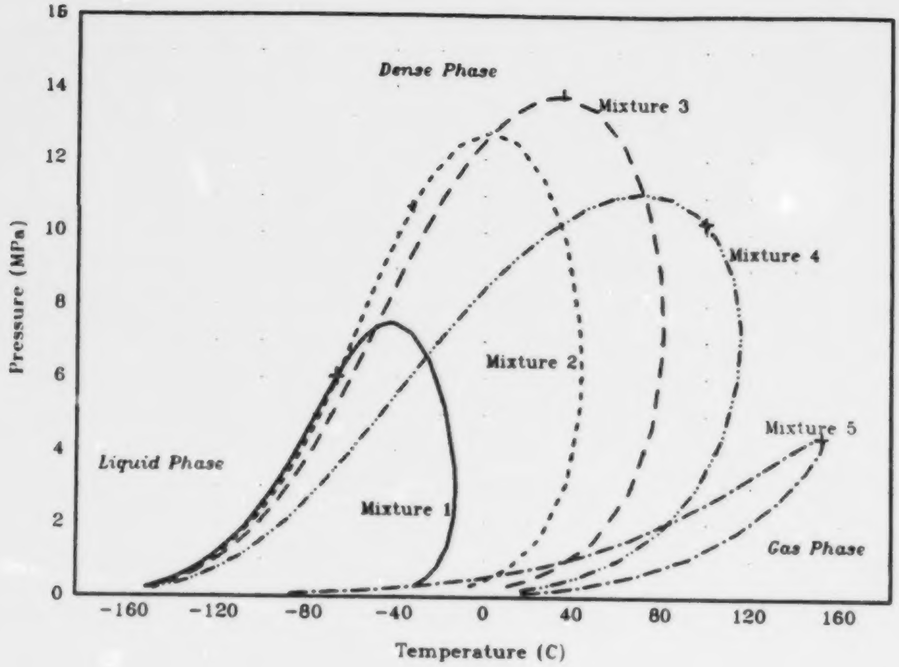

Figure 1: Phase envelopes for five mixtures.

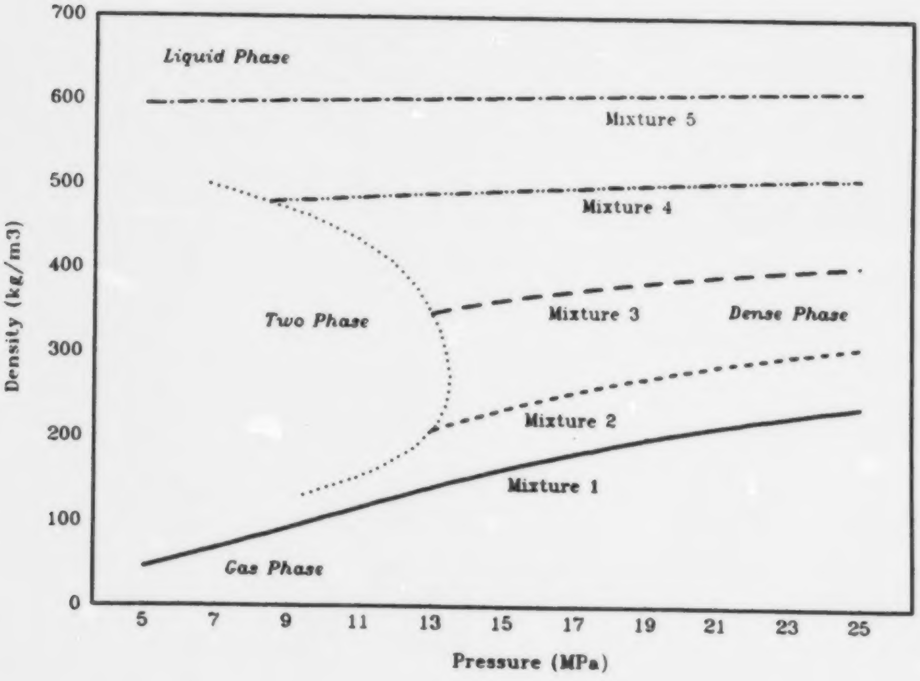

Figure 2: Density at 0 C for five mixtures.

Prediction of pipeline performance relies on accurate mixture properties. The five hydrocarbon mixtures range from a lean hydrocarbon gas with a molecular weight of 17.6 (Mixture 1) through progressively richer gases to a gas liquids stream with a molecular weight of 57.0 (Mixture 5). One of the most accurate techniques for predicting gas and liquid properties over a wide range of pressures is the BWRS equation of state using the generalized correlation parameters developed by Starling and Han.[5]

Thermodynamic properties which are useful in designing Arctic pipelines where temperature effects are important include the Joule-Thomson coefficient and the isentropic temperature exponent. Thermodynamically consistent values for these and other properties were developed for this paper using Starling and Han's generalized constants and the BWRS equation of state. Values for density, Joule-Thomson coefficient and isentropic temperature exponent at 0°C for the five mixtures are shown on Figures 2, 3 and 4 respectively.

The densities of Figure 2 show that Mixture 1 behaves like a gas. Its density at 10 MPa is approximately 100 kg/m^3 and its density at 20 MPa is approximately 200 kg/m^3. Mixture 5 behaves like a liquid at pipeline pressures. At 0°C its density remains constant at approximately 600 kg/m^3. The other three mixtures exhibit a uniform transition in behaviour from gas to liquid.

The temperature of Arctic pipelines is important because of frost heave and thaw settlement problems associated with permafrost terrain. Pipeline temperature profiles and temperature rise in pumps and compressors need to be predicted accurately, and refrigeration units need to be sized properly to return the gas to the pipeline at sub-freezing temperatures. For those reasons temperature related properties such as Joule-Thomson coefficient and isentropic temperature exponent need to be calculated accurately on a consistent basis. The Joule-Thomson coefficient is defined thermodynamically by:

$$J = \left(\frac{\partial T}{\partial P}\right)_H \qquad \ldots \quad 1$$

The Joule-Thomson coefficients shown on Figure 3 reveal the pressure-sensitive temperature behaviour of lean gases like Mixture 1 at 0°C and conventional pipeline pressures. In the range 6 to 10 MPa its Joule-Thomson coefficient is approximately 8 K/MPa due to expansion cooling effects. A typical system with a pressure loss of 2 MPa between suction and discharge conditions could experience a temperature drop as high as 16°C between stations.

Mixture 5 has a Joule-Thomson coefficient that is typical of a liquid. It heats slightly at 0.5 K/MPa due to frictional dissipation of pressure energy as it flows along the pipeline. Its flowing temperature therefore can conform closely to ground temperature. Mixtures 2, 3 and 4 have Joule-Thomson coefficients between Mixtures 1 and 5 but are closer in behaviour to Mixture 5.

The isentropic temperature exponent for the five mixtures is shown on Figure 4. It is often referred to as the ratio of specific heats although at pipeline pressures it is not identical with the value of C_P/C_V. It is used to predict temperature rise through pumps and compressors and is defined implicitly for small pressure ratio isentropic processes by:

$$T_D = T_s \left(\frac{P_D}{P_S} \right)^{\frac{k-1}{k}} \qquad \ldots 2$$

Figure 4 shows that the isentropic temperature exponent of Mixture 1 has high values at 0°C and conventional pipeline pressures. Mixture 1 will therefore exhibit a large temperature rise during compression which counterbalances its large temperature drop as it flows along the pipeline due to its high Joule-Thomson coefficient. Mixture 5, on the other hand, behaves like a liquid and has a value of isentropic temperature exponent close to unity. Its temperature rise during pumping will be comparatively small. The other three mixtures have exponents that lie between Mixtures 1 and 5.

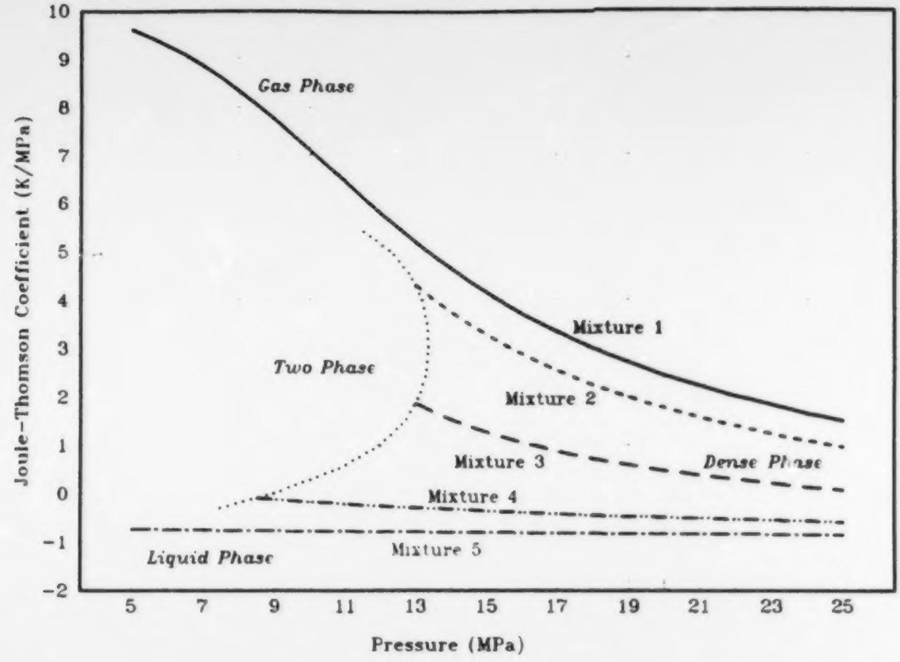

Figure 3: Joule-Thomson coefficient at 0 C for five mixtures.

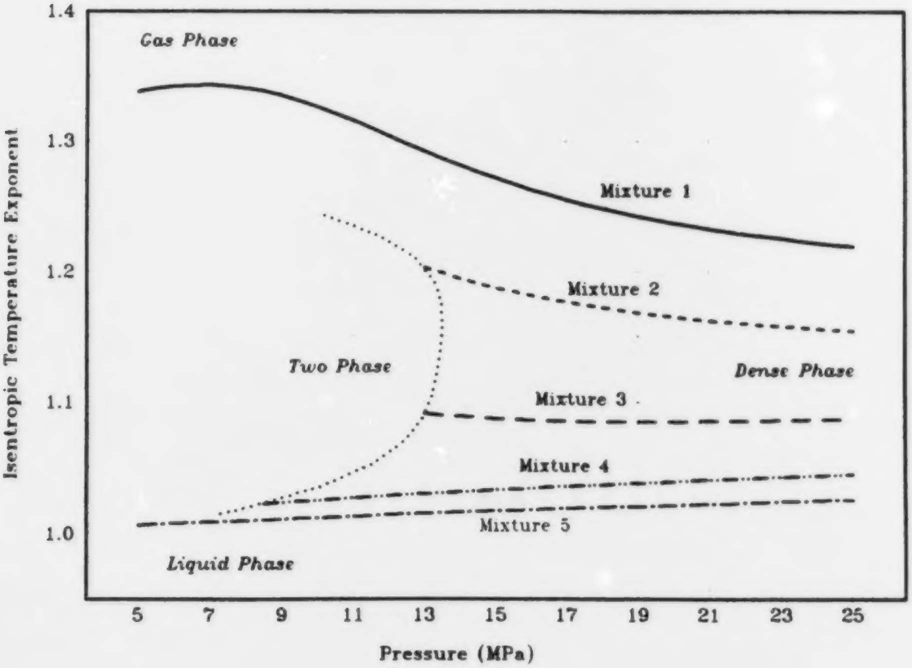

Figure 4: Isentropic temperature exponent at 0 C for five mixtures.

ENVIRONMENT

The approximate extent of permafrost zones in Canada is shown on Figure 5. Pipelines from the Mackenzie Delta and Beaufort Sea in the Canadian Arctic must traverse more than 1500 km of continuous and discontinuous permafrost before connecting with existing pipeline systems in Alberta.

Permafrost terrain provides unusual engineering challenges such as thaw settlement and frost heave which can cause large differential movements over short distances and can overstrain buried pipelines. Furthermore, Arctic environments tend to be fragile. Clearing ground cover to bury pipelines can have far-reaching effects on the thermal regime of the subsoil, leading to permafrost regression and severe surface erosion unless the right-of-way is carefully revegetated. Buried pipeline designs for Arctic regions therefore need to incorporate concepts which can cope with the difficulties encountered along the route and which can minimize environmental disturbances.

The large Joule-Thomson coefficient of lean gases like Mixture 1 at 0°C causes problems for buried gas pipelines in permafrost terrain. If station discharge temperatures are maintained at just below freezing to preserve the permafrost, station suction temperatures at the next downstream station can fall to -15°C. This can cause ice lensing and frost heave problems particularly at the thousands of interfaces between frozen and unfrozen ground that are encountered along pipeline routes through both continuous and discontinuous permafrost zones. Figure 6 shows how frost heave can oval and buckle the pipe at these interfaces.

Insulation has been proposed to reduce the severity of frost heave problems at interfaces between frozen and unfrozen ground, but it only delays the onset of differential heave movements.[7] After differential movement begins, the insulation can be crushed at the interfaces reducing its effectiveness and increasing the rate of frost heave. The long-term effectiveness of insulation in preventing potentially harmful frost heave is therefore uncertain, but high strength insulation systems which are tough enough to resist the forces associated with differential movements along the

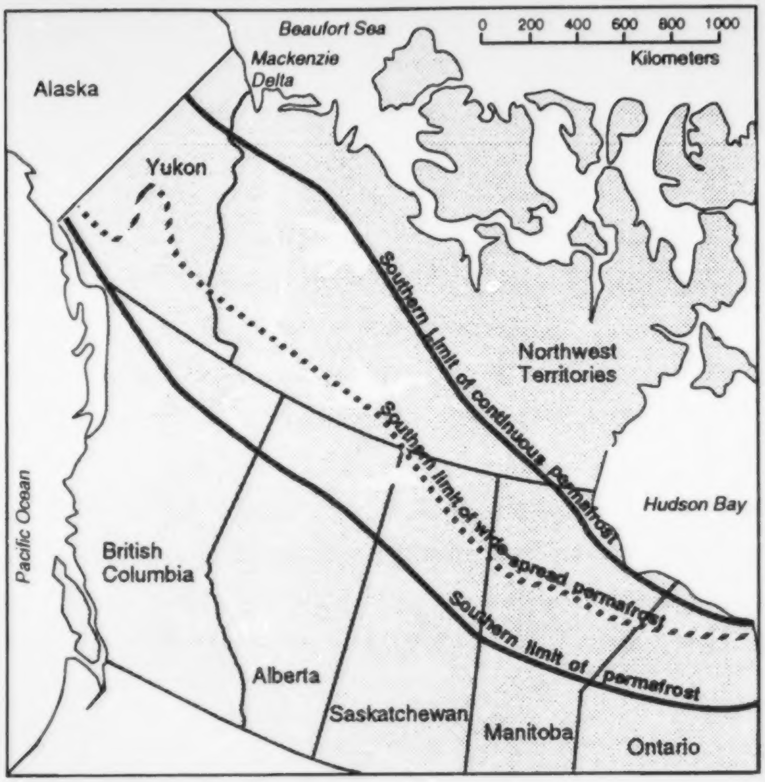
Beaufort Sea
0 200 400 600 800 1000
Kilometers
Mackenzie Delta
Alaska
Yukon
Southern Limit of continuous permafrost
Northwest Territories
Southern limit of wide-spread permafrost
Hudson Bay
Pacific Ocean
British Columbia
Southern limit of permafrost
Alberta
Saskatchewan
Manitoba
Ontario

Figure 5: Permafrost zones in Western Canada [6]

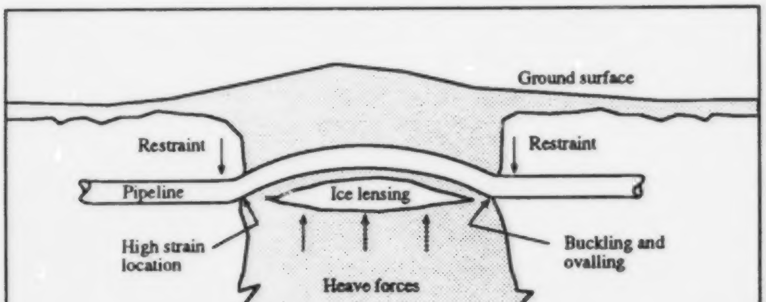
Ground surface
Restraint
Restraint
Pipeline
Ice lensing
High strain location
Buckling and ovalling
Heave forces
Permafrost
Unfrozen ground
Frost stable ground

Figure 6: Differential frost heave at interfaces

pipeline could be developed. Heat tracing has also been proposed to reduce the severity of frost heave around buried pipelines operating at sub-freezing temperatures.[7] The cost of high strength insulation and heat tracing has not been considered in the comparisons that are made later in this work.

Figure 3 shows that the value of the Joule-Thomson coefficient decreases at higher pressures and for richer gases. For example, Mixture 1 has a Joule-Thomson coefficient of 2.5 K/MPa at 20 MPa compared with 8 K/MPa at 8 MPa and Mixture 3 has a value of only 0.5 K/MPa at 20 MPa. Ultra-high pressure pipelines carrying rich gases therefore flow at temperatures that conform more closely to ground temperature and are less likely to cause frost heave or thaw settlement problems than conventional pipelines carrying lean gas. They would cause less environmental disturbance on this account and would eliminate the need for a separate gas liquids pipeline, further reducing environmental disturbance.

DESIGN

Pipelines need to be designed on a common basis in order to make fair comparisons between alternatives. The following formulae and assumptions provide a physically realistic description of pipeline and compressor performance and were used consistently for all systems. Pressure loss along a section of pipe was calculated from:

$$dP = \frac{2f\rho v^2}{D}\, dl \qquad \ldots 3$$

Velocity (v) in Equation 4 can be replaced by mass flow rate using:

$$m = \rho v \frac{\pi D^2}{4} \qquad \ldots 4$$

All systems that were analyzed had high Reynolds numbers so that frictional effects followed the rough pipe law:

$$\frac{1}{\sqrt{f}} = 4 \log_{10}\left(\frac{3.7D}{k_e}\right) \quad \ldots 5$$

Power requirements of pumps and compressors were calculated from:

$$dW = \frac{m}{E_c \rho} dP \quad \ldots 6$$

As a rough rule of thumb for a wide variety of systems, optimum power per unit length of a pipeline is approximately proportional to mass flow rate:

$$\frac{dW}{dl} = C_f m \quad \ldots 7$$

The constant of proportionality (C_f) has been named in this paper the "power to pipe factor." It has the dimensions of force per unit mass and provides a measure of the force applied by pumps or compressors to propel fluid along the pipeline. Its optimum value is slightly affected by density, mass flow rate and pipe diameter as well as by relative costs of fuel, station equipment, and pipe. For scoping studies of this kind it is convenient to fix the power to pipe factor at a constant value for all cases. For this paper a value of 0.25 N/kg was chosen based on results of detailed optimization of large diameter Arctic natural gas pipelines[3] and on experience with the optimization of liquid pipelines.

The pressure differential (ΔP) between suction pressure and discharge pressure can be obtained by integrating Equation 3 and adding station losses:

$$\Delta P = \frac{2f\rho v^2 L}{D} + \Delta P_L \quad \ldots 8$$

The pipeline design pressure can then be found using the average pressure (P) from:

$$P_D = P + \frac{\Delta P}{2} \quad \ldots 9$$

Since diameter (D) in these equations is the inside diameter, the Barlow formula for wall thickness needs to be modified slightly:

$$t = \frac{P_D D}{2 (\sigma_y F - P_D)} \qquad \ldots 10$$

Finally, the pipe mass per unit length can be found from:

$$M = \pi (D + t) t \rho_s \qquad \ldots 11$$

Equations 3 through 11 were solved for pipe inside diameter (D), design pressure (P_D), wall thickness (t) and pipe mass (M) for a range of values of average pressure (P) and mass flow rate (m) using the values for other parameters specified in Table 2.

Parameters	Symbol	Value
Pipe effective roughness	k_e	18 µm
Mixture density	ρ	Fig. 2
Pump and compressor efficiency	E_c	0.8
Station spacing	L	80 km
Power to pipe factor	C_f	0.25 N/kg
Station pressure losses	ΔP_L	0.50 MPa
Pipe design factor	F	0.8
Steel SMYS	σ_y	483 MPa
Steel density	ρ_s	7.9 Mg/m^3

Table 2: Input parameters and values

The relationship between pipe inside diameter and design pressure of systems carrying 500 and 1000 kg/s for the five different mixtures set out on Table 1 are shown on Figures 7 and 8. As anticipated, pipe diameters for Mixture 1 decrease with increasing pressure because Mixture 1 behaves like a gas at pipeline pressures. Pipe diameters for Mixture 5 are unaffected by pressure because Mixture 5 behaves like a liquid. Pipe diameters for Mixtures 2, 3 and 4 lie between Mixtures 1 and 5.

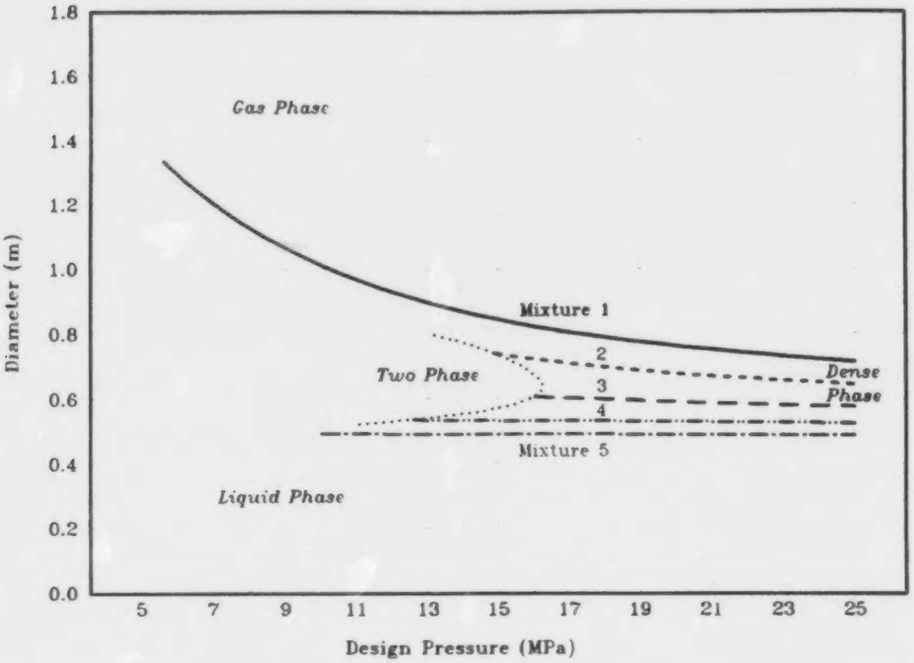

Figure 7: Diameter of pipelines carrying 500 kg/s at 0 C.

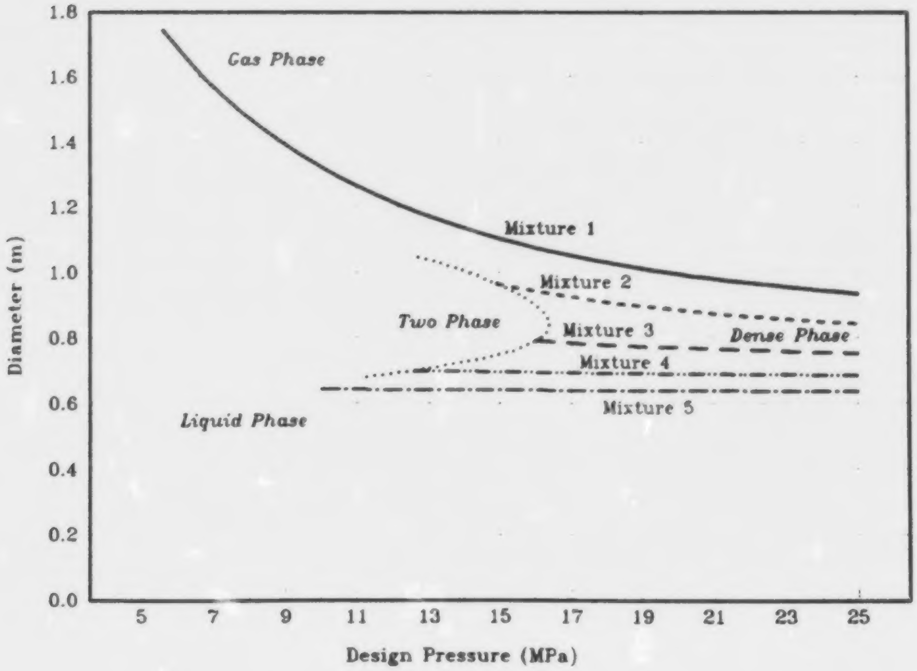

Figure 8: Diameter of pipelines carrying 1000 kg/s at 0 C.

Wall thicknesses for systems carrying 500 and 1000 kg/s are given on Figures 9 and 10 respectively. Because pipe diameters for Mixture 1 decrease with increasing pressure, wall thicknesses for Mixture 1 do not increase in direct proportion to design pressure. For Mixture 5, pipe diameter remains constant for any pressure and wall thickness increases in direct proportion to the pressure. Wall thicknesses for Mixtures 2, 3 and 4 follow a smooth gradation between Mixture 1 to Mixture 5.

COMPARISONS

It has already been established by studying thermodynamic properties that the temperature of ultra-high pressure pipelines carrying rich gases can conform more closely to ground temperature, reducing frost heave and thaw settlement problems. In addition, higher fluid dencities and pressures lead to smaller diameter pipes with thicker walls which are better able to handle differential frost heave and thaw settlement movements.

The question to be resolved at this stage is whether gas pipelines designed to operate at ultra-high pressures can compete economically with pipelines designed to operate at conventional pressures.

To distinguish between similar systems in the early stages of concept development, it is meaningful to compare them on a physical basis. For this work all systems have the same distance between stations and the same power requirements per unit mass of gas delivered. This means that systems delivering the same quantity of gas can be compared in terms of number of pipes, pipe diameter, wall thickness and pipe mass.

The rationale for comparing systems on a mass flow basis is that the constituent components of oil and gas have similar specific heating values (Table 3). Therefore systems which have the same mass flow rate are comparable in terms of the amount of energy they deliver. Some of the components of natural gas are more valuable than others to the petrochemical industry but such issues go beyond the scope of this study.

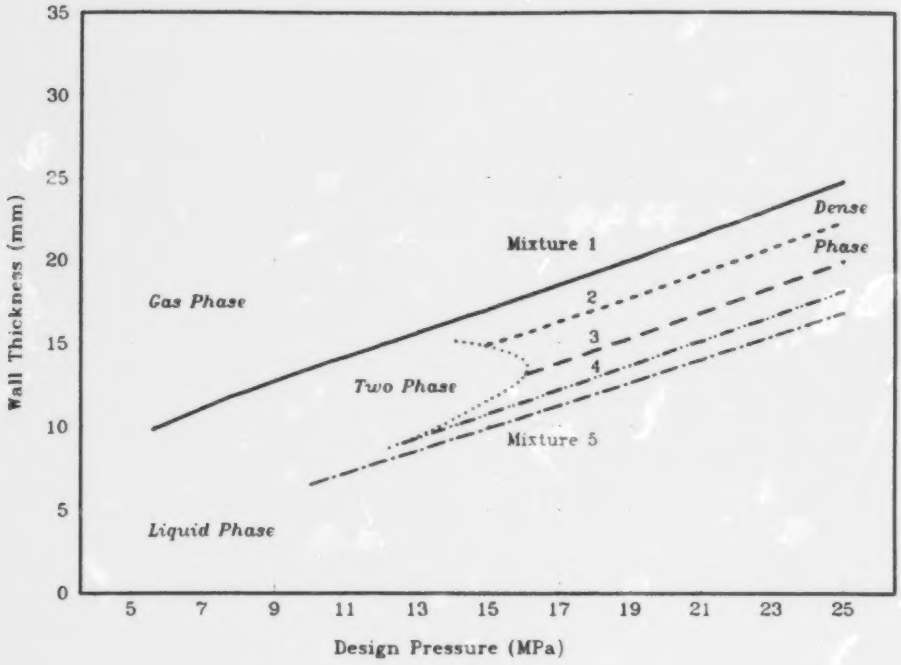

Figure 9: Wall thickness of pipelines carrying 500 kg/s at 0 C.

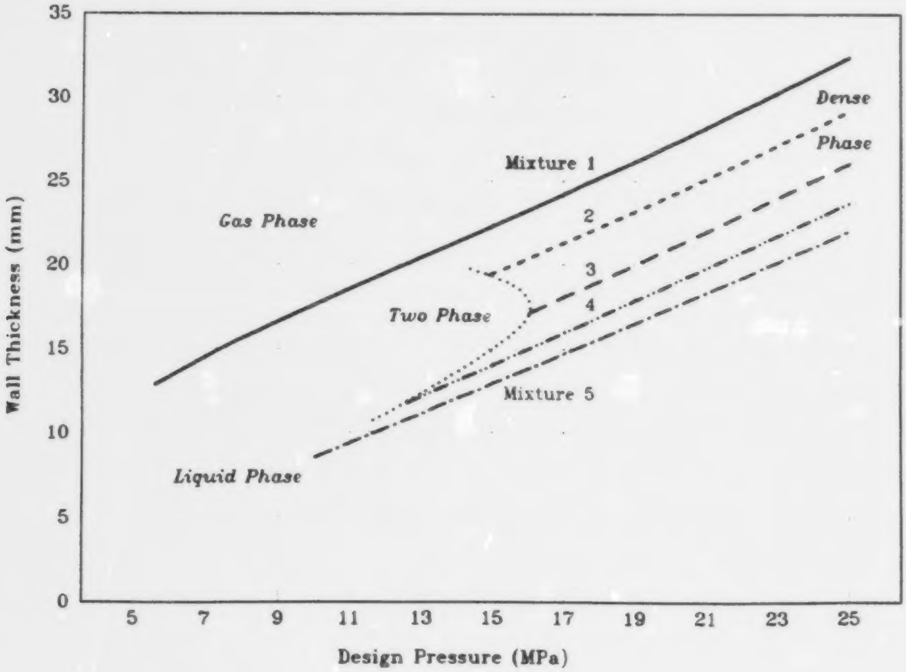

Figure 10: Wall thickness of pipelines carrying 1000 kg/s at 0 C.

Component	Gross Heating Value MJ/kg
Methane	55.561
Ethane	51.586
Propane	50.000
Butane	49.158
Pentane	48.667
Hexane	48.344
Heptane	48.104
Octane	47.919
Nonane	47.783
Decane	47.670

Table 3: Heating values of hydrocarbons [8]

One of the drawbacks attributed to ultra-high pressure pipelines is extra initial compression, but it can be largely recovered at the delivery end of the pipeline by the elimination of compressor stations. This reduces the penalty of extra initial compression to an amount that would be negligible for a long distance Arctic pipeline.

Ultra-high pressure pipelines carrying 500 and 1000 kg/s were compared with conventional pressure systems carrying the same quantity of each hydrocarbon component. A design pressure of 20 MPa was chosen for the ultra-high pressure pipelines to provide a sufficient margin against the formation of liquids in the two-phase region. A design pressure of 10 MPa was chosen for the conventional pressure systems and this required two pipelines to avoid two-phase flow - a gas pipeline for Mixture 1 and a liquids pipeline for Mixture 5.

Details of the ultra-high pressure pipelines and each separate pipeline of the two-pipe conventional pressure systems are given on Tables 4 and 5. Comparisons of pipe mass required for the ultra-high pressure pipelines and the conventional pressure two-pipe systems are shown on Figures 11 and 12. Ultra-high pressure pipelines carrying gases with molecular weights in the range from 20 to 40 use a similar amount of steel as the conventional systems even though they have twice the design pressure. This is due in part to the

System		Ultra-High	Conventional	Ultra-High	Conventional	Ultra-High	Conventional	Ultra-High	Conventional	Ultra-High	Conventional
Design Pressure	MPa	20	10	20	10	20	10	20	10	20	10
Mixture Number		1	1	2	1 & 5	3	1 & 5	4	1 & 5	5	5
Molecular Weight											
Gas		17.63	17.63	21.56	17.63	27.47	17.63	37.31	17.63	-	-
Liquids		-		-	57.00	-	57.00	-	57.00	57.00	57.00
Mass Flow Rates											
Gas	kg/s	500	500	500	368	500	241	500	118	-	-
Liquids	kg/s	-	-	-	132	-	259	-	382	500	500
Total	kg/s	500	500	500	500	500	500	500	500	500	500
Station Power											
Compressor	MW	10.0	10.0	10.0	7.4	10.0	4.8	10.0	2.4	-	-
Pump	MW	-	-	-	2.6	-	5.2	-	7.6	10.0	10.0
Total	MW	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Pipe Diameter											
Gas Pipe	mm	761.7	1013.0	676.8	899.4	588.4	763.2	527.7	579.5	-	-
Liquids Pipe	mm	-	-	-	293.8	-	381.2	-	442.7	487.3	491.2
Wall Thickness											
Gas Pipe	mm	20.8	13.5	18.5	11.9	16.1	10.1	14.4	7.7	-	-
Liquids Pipe	mm	-	-	-	3.9	-	5.1	-	5.9	13.3	6.5
Pipe Steel Mass											
Gas Pipe	kg/m	403.8	342.8	318.7	270.2	240.9	194.6	193.7	112.2	-	-
Liquids Pipe	kg/m	-	-	-	28.8	-	48.5	-	65.5	165.3	80.6
Total	kg/m	403.8	342.8	318.7	299.0	240.9	243.1	193.7	177.7	165.3	80.6

Table 4: Physical comparison of single ultra-high pressure pipelines and two-pipe conventional systems carrying 500 kg/s.

System		Ultra-High	Conventional	Ultra-High	Conventional	Ultra-High	Conventional	Ultra-High	Conventional	Ultra-High	Conventional
Design Pressure	MPa	20	10	20	10	20	10	20	10	20	10
Mixture Number		1	1	2	1 & 5	3	1 & 5	4	1 & 5	5	5
Molecular Weight											
Gas		17.63	17.63	21.56	17.63	27.47	17.63	37.31	17.63	-	-
Liquids		-	-	-	57.00	-	57.00	-	57.00	57.00	57.00
Mass Flow Rates											
Gas	kg/s	1000	1000	1000	736	1000	481	1000	236	-	-
Liquids	kg/s	-	-	-	264	-	519	-	764	1000	1000
Total	kg/s	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Station Power											
Compressor	MW	20.0	20.0	20.0	14.7	20.0	9.6	20.0	4.7	-	-
Pump	MW	-	-	-	5.3	-	10.4	-	15.3	20.0	20.0
Total	MW	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Pipe Diameter											
Gas Pipe	mm	996.2	1325.1	885.1	1176.5	769.4	998.1	689.9	757.7	-	-
Liquids Pipe	mm	-	-	-	384.0	-	498.3	-	578.7	637.1	642.3
Wall Thickness											
Gas Pipe	mm	27.2	17.6	24.2	15.6	21.0	13.3	18.8	10.1	-	-
Liquids Pipe	mm	-	-	-	5.1	-	6.6	-	7.7	17.4	8.5
Pipe Steel Mass											
Gas Pipe	kg/m	690.6	586.6	545.1	462.4	411.9	332.8	331.2	191.8	-	-
Liquids Pipe	kg/m	-	-	-	49.3	-	82.9	-	111.9	282.5	137.8
Total	kg/m	690.6	586.6	545.1	511.7	411.9	415.7	331.2	303.7	282.5	137.8

Table 5: Physical comparison of single ultra-high pressure pipelines and two-pipe conventional systems carrying 1000 kg/s.

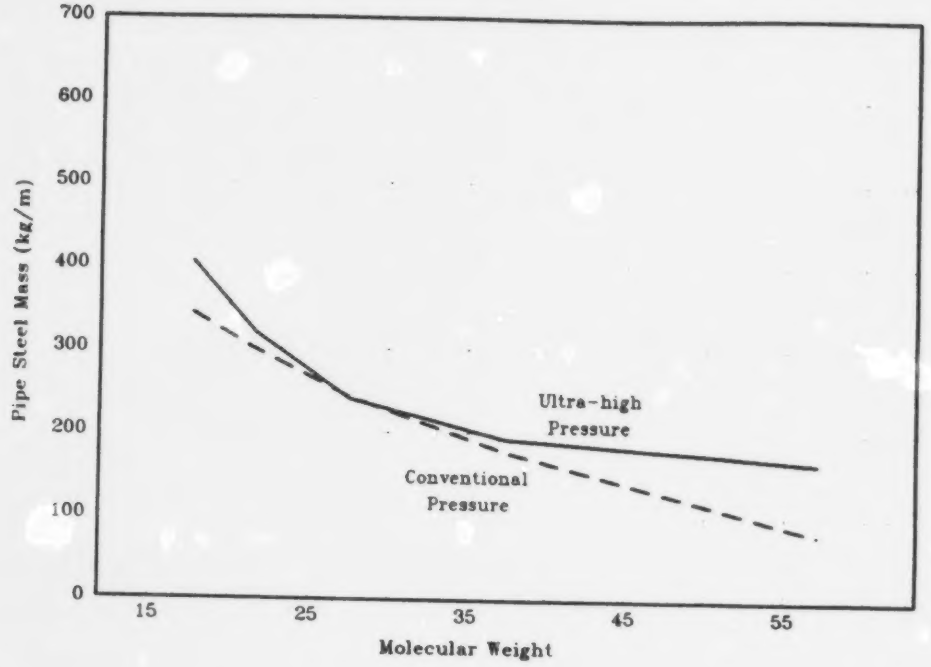

Figure 11: Pipe mass for pipelines carrying 500 kg/s at 0 C.

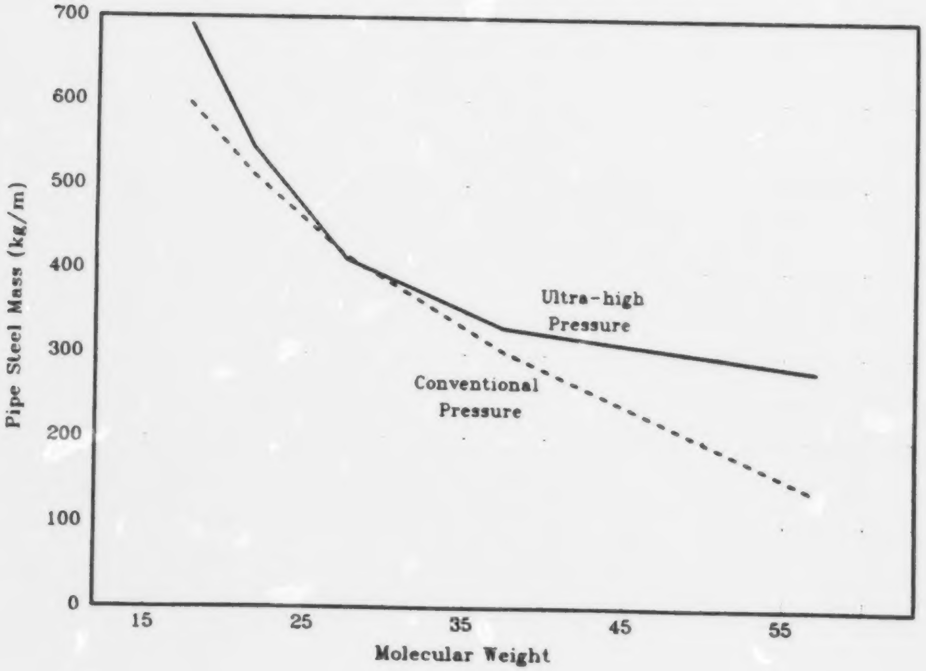

Figure 12: Pipe mass for pipelines carrying 1000 kg/s at 0 C.

volumetric shrinkage that occurs when Mixture 1 and Mixture 5 are combined. For example, from Figure 2 at 20 MPa and 0°C, Mixtures 1, 2 and 5 have densities of approximately 205, 280 and 610 kg/m^3 respectively. Therefore, if 90 m^3 of Mixture 1 are commingled with 10 m^3 of Mixture 5 it will make only 88 m^3 of Mixture 2 ((90 x 205 + 10 x 610)/280 = 88).

In the unlikely event that only lean gas is available and no advantage can be taken of the volumetric shrinkage effect of commingling lean gas with gas liquids, an ultra-high pressure lean gas pipeline would use up to 20 percent more steel than a conventional pressure lean gas pipeline (Figures 11 and 12). In this case a decision would have to be made whether the advantages of having a more robust pipeline with lower environmental impact would counterbalance the increased cost of pipe steel.

CONCLUSIONS

Oil and gas reservoirs in the Canadian Arctic contain intermediate weight hydrocarbons such as ethane, propane and butane which are difficult to carry in conventional oil and gas pipelines. At normal pressures they cause vapour problems if they are included in the oil stream and they cause liquids problems if they are left in the gas stream. But at ultra-high pressures they can be commingled and transported successfully in a single dense phase. This eliminates the need for a separate gas liquids pipeline or for re-injection facilities.

Ultra-high pressure gas pipelines have a number of other features which make them well suited for Arctic service. For example, they require smaller diameters than conventional gas pipelines carrying an equivalent amount of gas. This make them more flexible and better able to conform elastically to differential movements from thaw settlement and frost heave. They also have thicker walls which make them better able to resist ovalling and buckling under extreme bending stresses.

More importantly, however, at ultra-high pressures natural gas flows at a constant temperature and does not exhibit the marked Joule-Thomson cooling effect characteristic of conventional gas pipelines. Ultra-high pressure gas pipelines can therefore be designed to flow at or near ground temperature like the Norman Wells oil pipeline, and advantage can be taken of the experience gained from its successful operation in permafrost terrain.

Physical comparisons show an ultra-high pressure pipeline carrying gas with molecular weight in the range 20 to 40 would use a similar amount of steel as an equivalent conventional high pressure gas pipeline with a separate gas liquids line. When their better environmental acceptability and durability is taken into account it can be concluded that ultra-high pressure pipelines deserve serious consideration for transporting natural gas from the Arctic.

ACKNOWLEDGEMENTS

The author would like to acknowledge the assistance of Lavalin Inc., Tensor Engineering Limited and Alex Huddleston in developing this paper.

NOMENCLATURE

C_f	power to pipe factor (N/kg)
C_p	specific heat at constant pressure (J/kg-K)
C_v	specific heat at constant volume (J/kg-K)
D	pipe inside diameter (m)
E_c	compressor/pump efficiency (-)
f	Fanning friction factor (-)
F	pipe design factor (-)
H	enthalpy (J/kg)
J	Joule-Thomson coefficient (K/Pa)
k	isentropic temperature exponent (-)
k_s	pipe effective roughness (m)
l	pipe length (m)
L	distance between stations (m)
m	fluid mass flow rate (kg/s)
M	pipe mass (kg/m)
P	average pressure (Pa)
P_D	discharge (design or MAOP) pressure (Pa)
P_S	suction pressure (Pa)
ΔP	pressure rise through compressor/pump (Pa)
ΔP_L	station pressure losses (Pa)
S	entropy (J/kg-K)
t	wall thickness (m)
T	average temperature (k)
T_D	discharge temperature (k)
T_S	suction temperature (k)
v	velocity (m/s)
W	compressor/pump power (W)
ρ	density of fluid (kg/m^3)
ρ_s	density of steel (kg/m^3)
σ_y	pipe steel SMYS (N/m^2)

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TRANS MOUNTAIN PIPE LINE COMPANY LTD.

TANK REHABILITATION AND TERTIARY CONTAINMENT

Jim Horner
Reynold Hinger

Trans Mountain Pipe Line's (TMPL) Edmonton Terminal is located immediately east of Edmonton City in Strathcona County. The facility serves as the primary injection point for crude oil and petroleum products into the Trans Mountain system. The surrounding industrial subdivision also serves as residence to other pipeline operators and oil refineries.

In January of 1985 TMPL experienced the failure of a 12,650 m^3 oil storage tank, at its Edmonton Terminal. The tank released its contents through a hole in the floor plate. The liberated oil was contained within the tank bay. As a result of this failure and subsequent examination of other tankage, Trans Mountain instituted a rehabilitation program to prevent any further failures. As this program progressed it was also decided to upgrade the Terminal's Tertiary Containment Facilities.

TANK REHABILITATION

The Tank Rehabilitation program has evolved into jacking and levelling of the tank, replacement of the annular bottom plate, construction of a new foundation and regrading of the tank bay. The last of 13 tanks affected by the program will be repaired this year. The opportune timing of this program was borne out by a second failure that occurred in late April of 1989. Fortunately this failure was a slow leak and the tank was taken out of service, before a significant quantity of oil was lost.

The failure in 1985 occurred in the only tank which still had a coal tar lining (applied in 1962). There was extensive corrosion in the floor plate adjacent the tank shell. The failure in 1989 occurred in a tank with a fibre glass lining (applied in 1972). The lining had cracked and delaminated from the shell. The underlying floorplate had corroded through. It was difficult to tell if the corrosion pre-existed the lining application, or had occurred after it had failed. Judging by the large number of patches on the tank floor, the corrosion had probably started prior to application of the tank lining.

Examination of each subsequent tank which was taken out of service for repair revealed the same pattern: excessive shell settlement, significant corrosion of the floor plate adjacent to the tank shell and partial delamination of the tank lining in the annular area. In many cases (due to pre-existing corrosion holes in the floor plate), the fibre glass lining acted as the primary containment. Some of the tanks had also experienced damage to the external floating roof due to distortion of the tank shell.

TANK SETTLEMENT

Settlement of a tank is considered to be the result of either one or a combination of the following three components.

> **Uniform Settlement** - Uniform settlement of the tank does not induce stresses in the tank structure. However uniform settlement may cause localized stresses at external connections to the tank, such as tank fill lines.
>
> **Planar Tilt or Rigid Body Tilting** - Excessive planar tilting of the shell may not overstress the tank, but it can cause binding of the annular seals in a floating roof and inhibit roof travel.
>
> **Nonplanar or Differential Settlement** - Because of the flexible nature of tankage, it is possible for the shell to settle in a nonplanar configuration. Nonplanar settlement may radially distort or overstress the shell. This distortion or ovality may also inhibit roof travel.

All tankage affected by excessive settlement were constructed in 1953. Original construction specifications are not readily available, but site inspection during the tank rebuilding program indicates that the tanks were founded on 10 to 15 cm of coarse sand. These tanks were originally a cone roof, side fill design with a slight cone up bottom. During the early 1970's the fixed cone roofs were removed and replaced by welded steel, pontoon style external floating roofs.

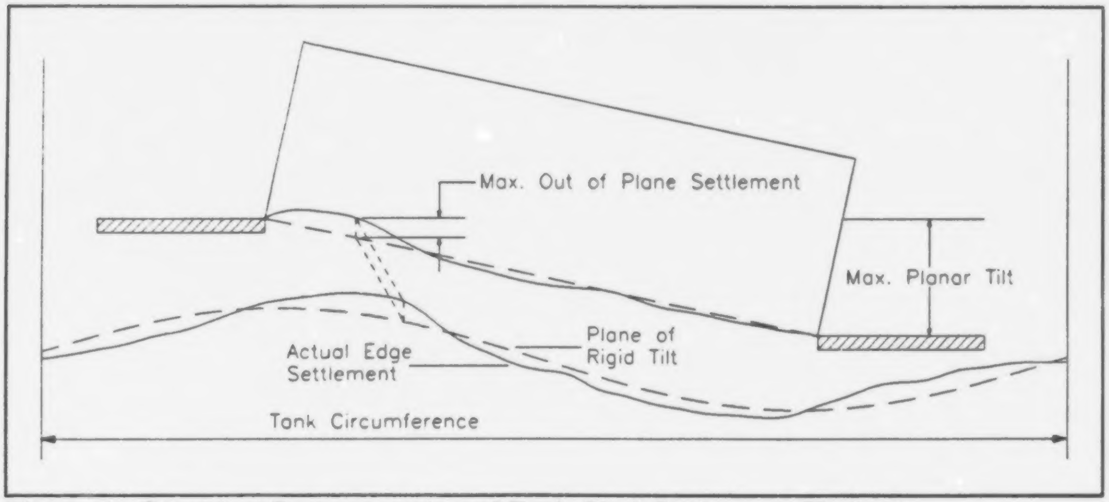

Figure 1: Graphical Representation of Tank Shell Settlement (Tank 5)

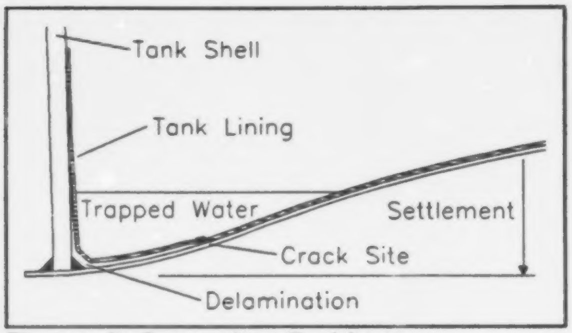

Figure 2: Secondary Problems

Settlement of the tank shell can also create secondary problems. In addition to overstressing of the annular floor plate, excessive differential settlement of the tank shell (relative to tank bottom) can create secondary problems such as: 1) a trap for the collection of water at the shell to floor connection; 2) delamination or cracking of the tank lining. The combination of these two situations can create corrosion problems as serious as the stresses imposed on the bottom plate by settlement. All of the tanks repaired exhibited these problems. The converse was true in the undistorted areas farther in from the shell. The lining was well adhered and when removed, clean bottom plate was found with primer intact.

Survey data typically indicated patterns of settlement with deformation concentrated under the shell where the bearing load is approximately 4 times that of the fully loaded interior. Tank settlement ranging from 25 to 46 cm was experienced at the tank perimeter with greater settlement to the north west. An explanation for this is the possible increase in frost penetration on this side as a result of shading and the reduction of snow cover on the side of prevailing winds.

The extent and type of settlement experienced by some of TMPL's Edmonton Tankage is listed in Table 1. Column A shows the maximum Non Planar settlement observed on each tank. The number indicates the greatest deviation from a sinusoidal fit to the tank rim elevation data. These values are well below the limits suggested in Appendix B of API Standard 653[1] for these tanks.

Column B indicates the planar tilt found on each tank. No limits have been suggested for this type of settlement by API, but the Tanks encountering the highest overall and unit tilt (column C) also experienced pontoon damage. Tanks 12 and 15 had ruptured pontoons and Tank 13's pantograph hangers had bent and were wearing on the end of the pontoon. This damage did not impair the operation of these floating roofs however. In Tank 15's case, the pontoon damage was not visible because the rupture was on the underside.

Column D shows the differential settlement of the tank shell relative to the bottom plate. The values indicated show the range found around the tank's circumference and this represents 85% of the shell settlement with respect to the tank center and only about 65% of the total settlement since original construction. This "relative" settlement measure indicates the extreme degree of stress experienced by the bottom plate in the region adjacent the tank shell. Appendix B of API Standard 653 suggests a maximum permissible settlement of 5 cm over a 1.68 m radius. In W. Allen Marr et el's paper "Criteria For Settlement of Tanks[2]" a maximum permissible value of 12.7 cm can be obtained if a risky safety factor of one is used.

Table 1: Tank Settlements

Tank	Dia. (m)	Height (m)	Non[A] Planar (cm)	Planar[B] Tilt (cm)	Unit[C] Tilt (cm / 30 m Dia.)	Shell[D] Bottom (cm)	Comment
5	36.6	12.2	2.1	11.5	9.3	15-23	Leak
6	36.6	12.2	0.8	15.0	12.3	13-20	
7	36.6	12.2	5.6	7.4	6.1	18-25	
8	36.6	12.2	2.0	11.2	9.2	18-28	
11	45.7	14.6	1.3	15.7	10.3	20-30	
12	45.7	14.6	4.8	23.4	15.4	20-25	Pontoon*
13	45.7	14.6	4.5	19.1	12.5	15-23	Pontoon*
14	45.7	14.6	2.0	5.1	3.3	20-25	
15	45.7	14.6	3.0	20.8	13.7	23-30	Pontoon*
16	45.7	14.6	1.5	13.2	8.7	18-23	Bottom Replaced

[A] Greatest deviation from the average tank plane

[D] Shell settlement relative to tank bottom, measured 1.68 m in from shell

* Tanks with pontoon damage

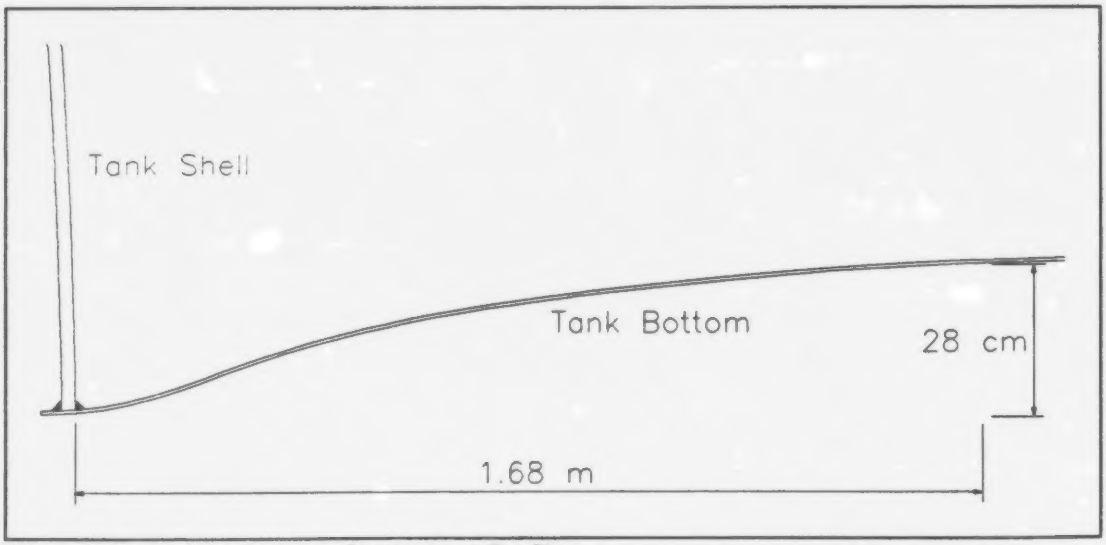

Figure 3: Typical Bottom Settlement Profile

GEOTECHNICAL BACKGROUND

The facility is located in an area underlain by ground moraine or glacial till materials. Ground moraine is defined as ice suspended material deposited through the bottom of a glacier. The area immediately west of the TMPL facility is overlain by glacio-lacustrine sediments (deposits formed in a glacial lake) that were deposited by glacial Lake Edmonton. This suggests that the site is close to the old shoreline of glacial Lake Edmonton (formed during the retreat of the most recent [Laurentide] glaciation some 10,000 years ago).

The facility is underlain by a coal seam which was commercially mined during the late 1800's. Historical mine survey data shows the probable position and extent of the Black Diamond Mine 99 mine works. This information provides evidence of mine shafts underlying the north portion of the TMPL quarter section (presently undeveloped) and properties adjacent to TMPL. As a result the possibility of mine works under existing tanks requiring rehabilitation has been ruled out. This was confirmed by bore hole testing undertaken as a part of geotechnical investigations for new tank construction. Test holes were drilled through the coal seam over a grid of locations at the site to ensure that remnants of mining operations do not exist under the area presently utilized.

GEOTECHNICAL INVESTIGATION

Geotechnical investigation of the terminal site revealed three strata having a significant effect on the integrity of tank foundations. This included a 660 mm thick high plastic clay layer immediately below the top soil and the glacial till deposits that exist in two layers from the 1.07 m depth to the bedrock level.

The thin clay layer immediately below the top soil varied between 0.25 and 1.5 m thick and is highly plastic. This soil requires a large amount of strain to reach peak strength and is sticky and unworkable over a large moisture range. The presence of this material in the original tank foundations may partially explain the excessive settlement. This clay is considered a poor foundation material because of its high plasticity. The normal construction practice in the area today is to excavate the entire clay layer and backfill with compacted structural fill.

The glacial till has a wide range of material sizes including varied amounts of clays, silts, sands and gravels. The material is low to medium plastic, with a water content of approximately 19%. The consistency is stiff to very stiff (high shear strength) with penetrometer shear strength of approximately 80 kPa. Standard Penetration (SPT) "N" values generally range between 15-20 blows/300mm (an indication of fair bearing strength). On a scale showing various soil strengths these values would be slightly above average for a glacial till. The till is considered a good foundation material because of its high shear strength and low settlement characteristics (as a result of over consolidation during glaciation).

The till material is only moderately susceptible to frost action (swelling) but could undergo substantial strength loss when subjected to continued freeze thaw cycles. The calculated frost penetration is approximately 2.4 m. Thermistor strings placed in boreholes since 1985 confirm this frost penetration. Frost depths of 2.3 m were measured around an uninsulated tank and 1.8 m around a tank insulated with 50 mm styrofoam.

FOUNDATION DESIGN EVOLUTION

The first foundation rebuild was completed in 1985 under Tank 5. The compressible clay below the tank perimeter was excavated and replaced with compacted granular fill. Elimination of voids under the floor plate was extremely difficult to achieve and settlement, while reduced, is evident since the repair. A possible reason for this may be the presence of additional moisture made available by the natural reservoir characteristics of the granular foundation. The additional moisture would also be expected to amplify freeze thaw action.

In recognition of this ground water problem, a system utilizing a sub surface drain tile in combination with compacted engineered fill was subsequently attempted in 1986 under Tank 11. This method achieved some success, but at the cost of a potential reduction in dyke containment integrity.

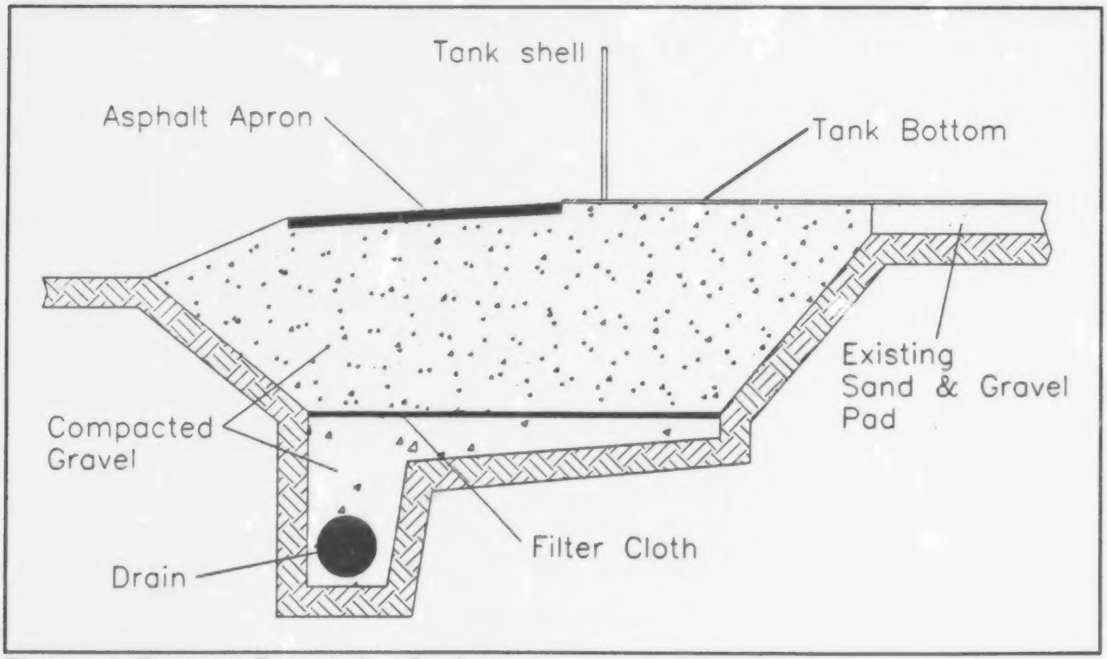

Figure 4: Tank 11 Foundation Design

Fill crete was used in 1987 under Tank 15 with extensive construction problems. These included: difficulty with slump reduction to achieve adequate placement; maintenance of adequate compressive strength; forming problems and extensive presence of voids under the floor plate. Solutions utilizing geotextile reinforcement and reinforced sketch plate were not considered because of the need for recompaction of engineered fill and the poor results achieved previously using recompaction methods.

A concrete ring beam foundation system was the third and final remedial technique attempted. This type of foundation has been utilized elsewhere in the petroleum industry where large tanks impose high shell loads on compressible soils. The advantage of this method is that it allows the placement of a ring beam foundation under an existing tank without raising the entire tank.

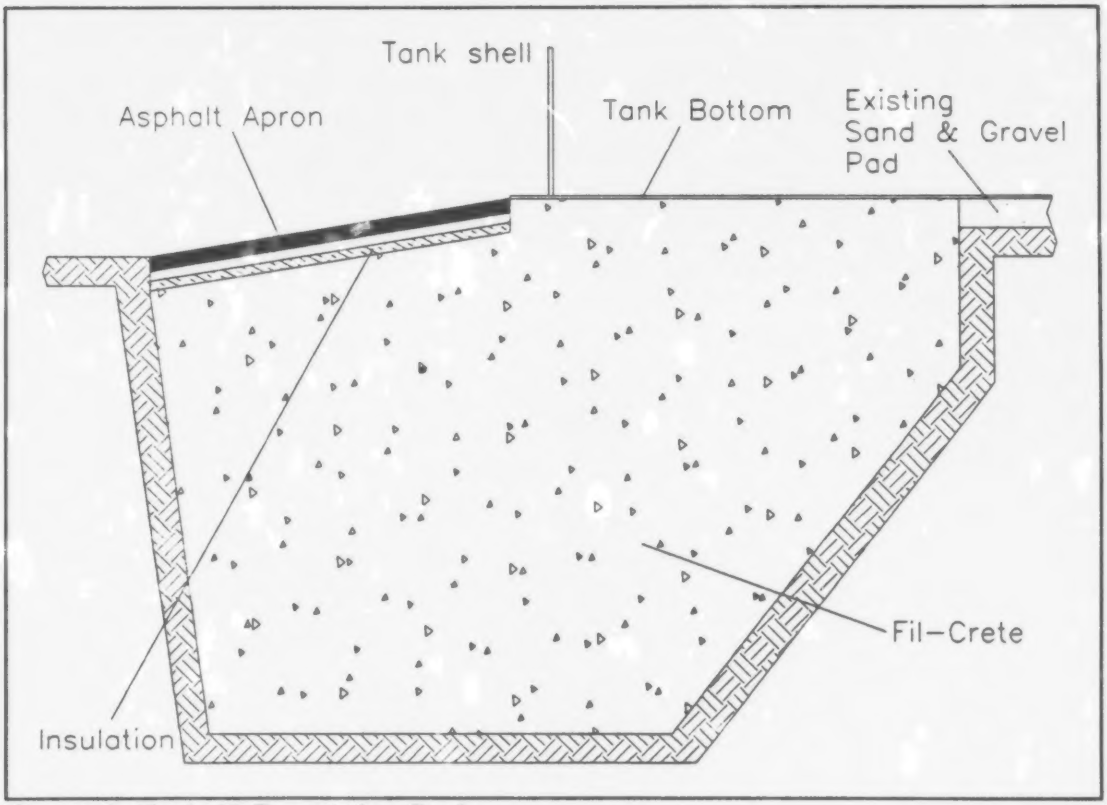

Figure 5: Tank 15 Foundation Design

The ring beam or ring wall foundation system provides a better distribution of the concentrated load from the shell. This improved distribution is achieved by better utilization of the shear strength of the soil on the side walls of the ring beam. The result is a superior foundation system at a marginal increase in cost.

As previously indicated the settlement profile, radially from the center of the tank, indicates excessive settlement starting at approximately 1.8 m from the shell, increasing to a maximum under the outer limits of the sketch plate and subsequently producing a swelling or heave in the soil immediately outside the termination of the floor plate. This deformation radially outward from the tank is thought to be the result of a shear failure and a displacement of material from under the tank.

Using earth pressure coefficients (the geotechnical equivalent of Poison's ratio) a radial stress calculation was completed. In addition to shear and bearing loads, the ring beam was designed for hoop stress capacity and circumferential stiffness. The ring beam was proportioned to resist a net outward pressure of 60 kPa at the top of the wall and decreasing uniformly to 41 kPa at the bottom of the wall. Hoop stress design incorporates the requirement to contain the cylinder of material under the tank and subsequently eliminate the radial deformation of material.

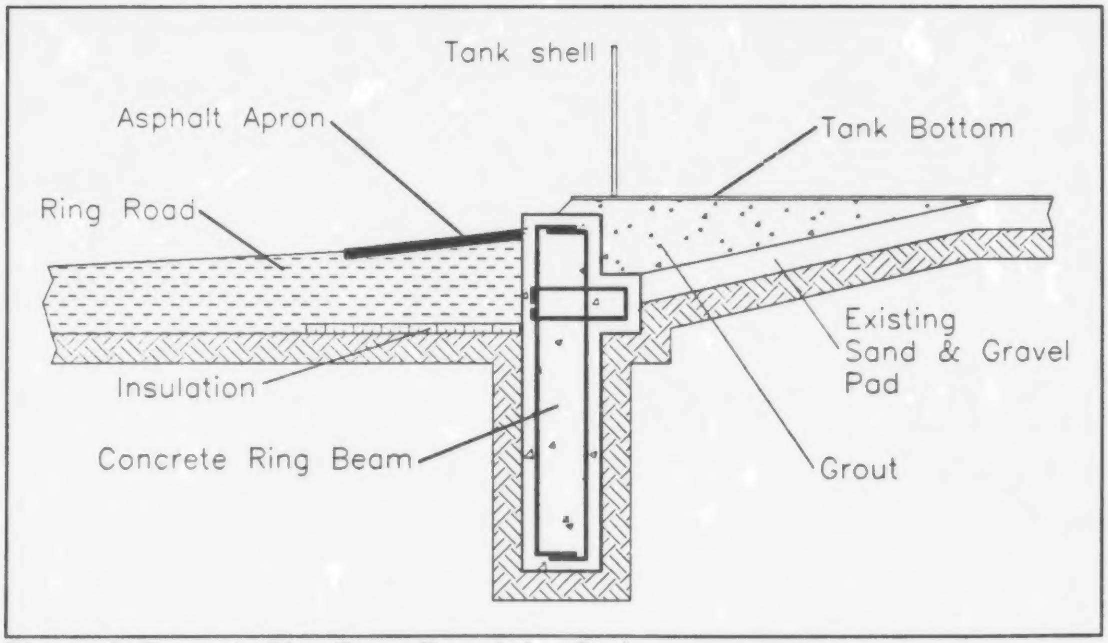

Figure 6: Concrete Ring Beam Foundation Design

THE CONSTRUCTION PROCESS

The tank rehabilitation process takes about 4 1/2 months and requires the participation of five construction contractors. The tank is first cleaned and gas freed. All external fillet welds and 36 patches, where lifting lugs are to be attached, are sandblasted to bare metal. The paint is removed from the external bottom weld to facilitate cutting off the external bottom or "Sketch" plate projection. The paint is removed from the remainder of the fillet welds around all tank nozzles and appurtenances to permit eventual magnetic particle examination.

The construction of the concrete ring beam follows removal of the sketch plate. The civil contractor cuts the grade down to the ring road base elevation and starts to excavate the subgrade portion of the ring beam. The outer sketch plate is removed to allow construction of the ring beam as close to the shell as possible. The upper portion of the ring beam is placed using fabricated forms, while the subgrade portion is formed using the sides of the trench. The beam is constructed in four or five segments. Each segment is usually excavated, formed and the concrete poured all within one day. The entire ring beam is usually placed within one week.

The concrete is allowed to cure for one week prior to any load being placed on it. During construction of the ring beam other contractors are working inside the tank removing portions of the bottom lining (60 mils of fibre glass laminate) and precutting portions of the tank bottom. The lining is removed to facilitate cutting the tank bottom plate. All of the deformed annular plate, 2.1 m in from the shell, will be removed and replaced after the tank has been jacked and levelled.

After the tank has been jacked to the desired elevation and levelled, the existing 6.25 mm thick, lap welded annular plate is removed and replaced with new 9.5 mm thick, butt welded steel. The new plate extends from 12.7 cm outside the shell into the tank and laps over the remaining interior bottom plate.

After the annular plate has been welded in place, a cement grout is pumped into the void that was created by lifting the tank. The grout is contained by placing foam cylinders between the tank sketch plate and the concrete ring beam. The "exposed" edge of the grout is later finished by hand trowelling. Care is taken to keep the grout level below the bottom of the sketch plate to prevent breakage during tank expansion.

The grout is given one week to cure before commencing the tank hydro test. In the period prior to the hydro test all lifting lugs and temporary supports are removed and the associated weld affected areas are ground smooth. The nozzle fillet welds and lug attachment points are subjected to a magnetic particle examination. Following approval of the examination results any required tank painting is undertaken.

After the hydro test water has been drained from the tank and the painting is completed, the tank lining is repaired. The new bottom plate is coated and repairs to the existing lining are made. Once this has been done the final phase of the civil work is completed. This includes: placement of the asphalt apron at the tank perimeter; grading of the perimeter ring road; and grading of the tank bay. This final portion of the civil work is designed to direct groundwater away from the tank foundation.

After the civil work has been completed and the tank lining has cured, the tank is bolted up and recommissioned. An outline of the costs involved in this program are presented in Table 3. These are the basic repair costs and do not include non related tank modifications such as floating roof seal replacement or installation or new tank mixers.

Table 2: Typical Construction Schedule

Construction Schedule	March					April				May				June					July			
Item	2	9	16	23	30	6	13	20	27	4	11	18	25	1	8	15	22	29	6	13	20	27
1) Tank Cleaning	■	■	■	■	■	■																
2) Ext. Sandblast							■															
3) Remove Sketch Pl.							■															
4) Ring Beam Construc.							■	■	■													
5) Remove Fibreglass								■														
6) Install Lugs										■												
7) Jack & Level Tank										■												
8) Remove Annular Pl.											■											
9) Install New Pl.											■	■	■									
10) Grout & Cure													■	■	■							
11) Coal Tar Pontoon														■								
12) Remove Lugs															■							
13) Hydrotest																■	■					
14) Clean out Silt																		■				
15) Paint exterior																	■	■				
16) Repair Lining																		■	■			
17) Grade Tank Bay																				■		

Table 3: Tank Repair Costs

Cleaning	$50,000
Tank Repair	
Jacking and Plate replacement	$167,000
Cleanout door installation	$28,000
Civil Contract	
Concrete Ring Beam	$77,000
Ring Road & Asphalt Apron	$29,000
Tank Bay Grading	$6,000
Tank Lining Repairs	$40,000
Tank Painting	$12,000
Engineering & Contract Supervision	$30,000
Total Cost	$439,000

CONCLUSIONS

At planar tilts greater than 12.5 cm per 30 m of tank diameter (5 in. per 100 ft.) the external floating roofs encountered pontoon damage. This suggests a lower damage threshold. However outright roof failure was never encountered and therefore no maximum tilt limit is indicated.

The two failures resulted from secondary settlement problems. Although stresses imposed on the bottom plate were significant, leakage resulted from failure of the tank lining and corrosion of the primary containment.

The first concrete ring beams used as a remedial technique have been in service since 1988. These foundations are performing well and provide an efficient and effective method for tank adjustment.

TERTIARY CONTAINMENT

An un-named creek runs east-west across the north portion of the TMPL Edmonton Terminal and it also crosses adjacent pipeline and refinery properties. The creek's drainage basin includes a large area of Strathcona County including portions of Sherwood Park. The creek then discharges into the North Saskatchewan River 2.4 km from the site. The ravine width on the TMPL property varies between 40 m and 90 m with an average depth of 3 m and sideslopes between 10% and 25%. The average stream gradient is 1.6%.

The water course operates under no-flow conditions for most of the winter and during the summer following extended periods of negligible precipitation. The discharge estimate for the 1:50 year event is 3.4 m^3/s (120 cfs) and 4.5 m^3/s (160 cfs) for the 1:100 year event. The original water control works, located where the water course exits the property, was constructed in the late 1950's primarily for spill control. These facilities also provided limited surface water storage. The antiquated controls have experienced operating problems and increased maintenance costs in recent years.

While the outline of the old mine works extends beneath the western limits of the ravine, the foundation of the existing water control structure is clear of any mine works. Research also indicates that only limited subsidence of the old control structure has occurred. Moreover, substantial structures have been built over old mine works a short distance north of the TMPL site and no problems have been encountered. Therefore, the old mine workings were not a concern in the design of the new Retention Works.

RETENTION WORKS DESIGN

Small oil spills have been experienced along this water course since 1950. While operating philosophy is dedicated to the prevention of such events, it is possible that a major spill by a pipeline operator or refinery into this watercourse could occur. Therefore the primary goal of the Retention Works is to provide dependable tertiary oil spill protection. This is provided by two control structures which provide a first and second line of defense.

The secondary goal is to reclaim low lying land on the south side of the creek for pipe storage and improve access to the large tract of land north of the creek designated for future expansion. Another benefit includes creation of a supplemental source of low cost water for fire fighting and hydro testing.

Working in cooperation with Alberta Environment, TMPL established a water handling capacity of a 1:100 year discharge rate as the primary sizing criteria. The secondary sizing criteria is a tertiary oil containment capacity of 23,700 m^3 during a 1:50 year discharge rate.

Identified early on, was the need for hands off operation. Facilities of this type rarely, if ever, see any regular operation, and subsequently receive a lower maintenance priority. As a result, when an emergency occurs, it is discovered much to everyone's surprise, that the facility is in need of repair or is not being operated properly.

RETENTION WORKS CONSTRUCTION

After a somewhat lengthy approval process for a Water License, construction on the Retention Works was initiated in May, 1990. Clearing and grubbing was completed mechanically and the top soil stripped to 1 m above the anticipated 100 year flood high water level.

Coffer dams and diversions were established and construction of the key was initiated. Culverts through the dam were later grouted and sealed. The dyke was constructed of till material excavated from the reservoir side of the dyke therefore adding to the water volume. The outlet structure is composed of a hexagon shaped weir around a vertical discharge column. This in turn feeds a 1.2 m dia. culvert which moves the discharge water through the dyke.

A lift station was constructed on a storm water line which was too low to be routed through the lower works. This insures that all surface runoff from the site flows through the Retention Works.

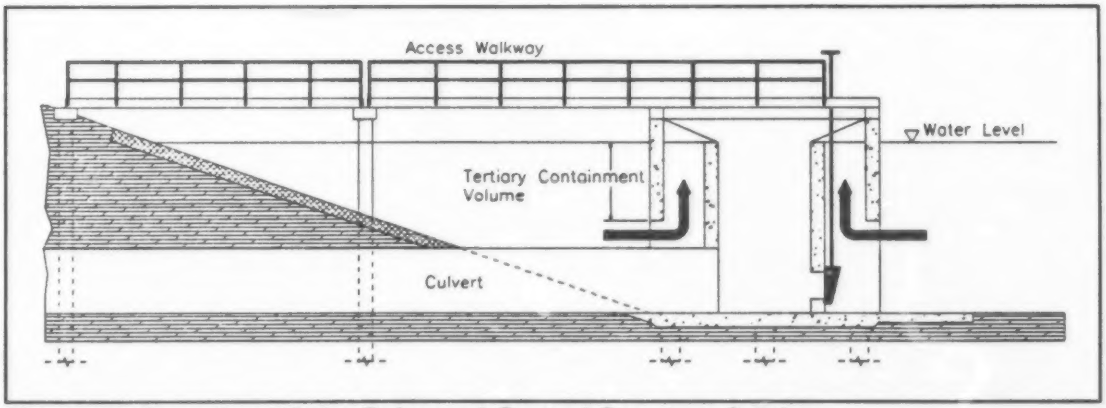

Figure 7: Retention Works Dyke and Control Structure Section

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1. "Tank Inspection, Repair, Alteration, and Reconstruction", API Atandard 653, First Edition, January 1991

2. W. Allen Marr, Jose A. Ramos and T. William Lambe, "Criteria For Settlement of Tanks", Journal of Geotechnical Engineering, Proceedings of the ASCE, August 1982

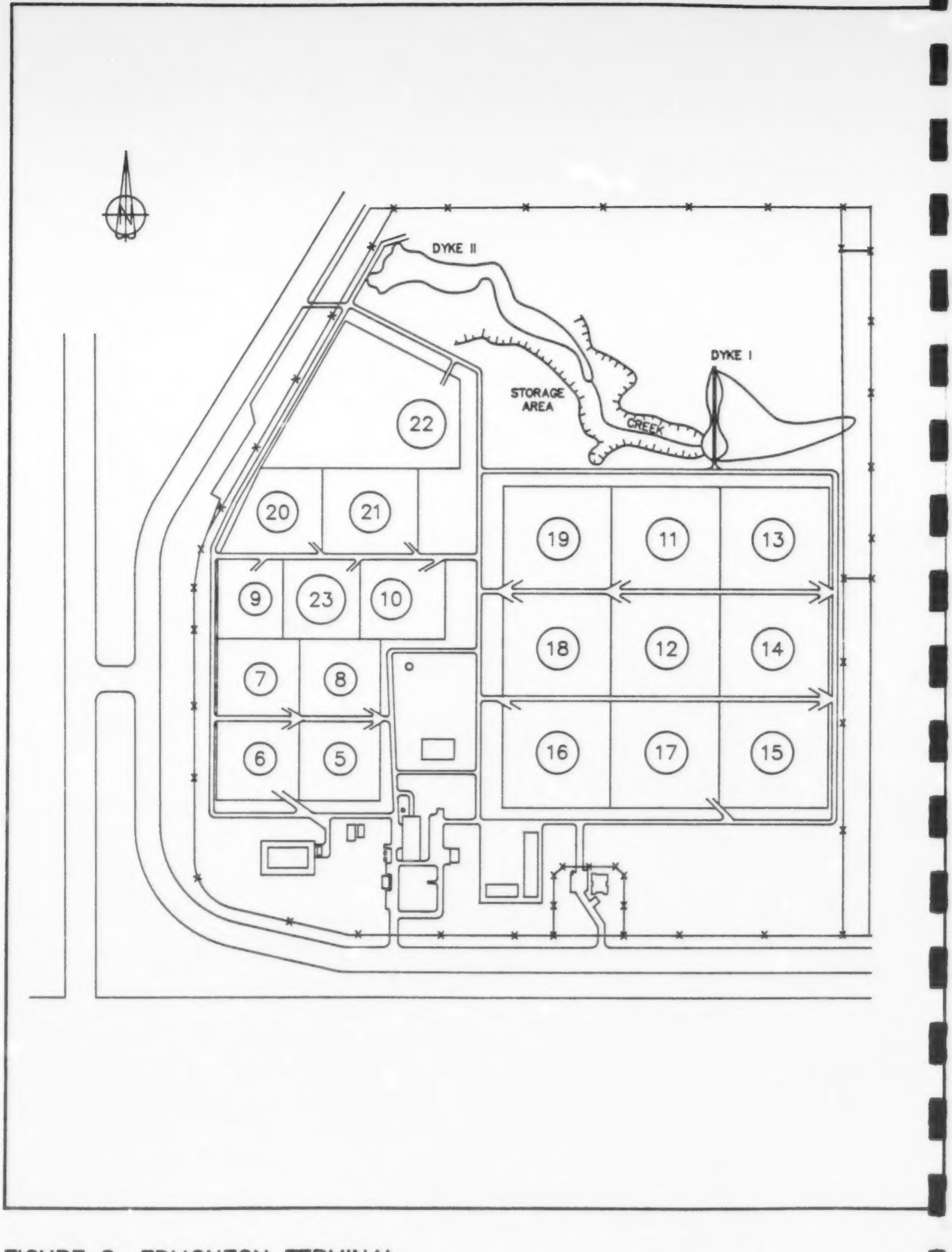
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FIGURE 8: EDMONTON TERMINAL

CANADIAN PETROLEUM ASSOCIATION

Fifth Annual Pipeline Conference

Palliser Hotel
May 14, 15 and 16, 1991
Calgary, Alberta

An Update on
THE IROQUOIS PROJECT

Presented by:

ROBERT J. REID
PRESIDENT
Iroquois Gas Transmission System
Shelton, Connecticut

I. INTRODUCTION

- Good Morning, ladies and gentlemen. It is certainly a pleasure to be back in Calgary this morning to provide you with an update on the progress of the Iroquois Gas Transmission System. And believe me--when I say it is a pleasure--I mean IT IS A PLEASURE!! After more than five years of regulatory review, Iroquois is now under construction. We are no longer a project, we are an interstate pipeline.

- The primary message that I want to convey to you this morning is both positive and straight forward: Iroquois is on track to bring a new secure supply of western Canadian natural gas to serve incremental markets in the Northeast commencing in November of this year.

- However, a secondary--and equally important--message is that notwithstanding the current recession, the Northeast offers Alberta producers the healthiest opportunity for market growth on this continent.

- During the four years I have been leading the Iroquois project, my remarks at various conferences and meetings have focused on providing updates on where our project stood in the regulatory process. Today, with the regulatory process behind us, it is a pleasure to be able to focus on construction of the pipeline itself, and review the tremendous opportunity the Iroquois project affords the North American gas industry.

II WHO IS IROQUOIS?

- The Iroquois pipeline is being constructed by the Iroquois Gas Transmission System, a partnership of 12 U. S. and Canadian energy companies. The partners in the Iroquois project can be divided into three groups:

TransCanada PipeLines	29.0%	
AEC Pipelines	6.0%	35.0%
Brooklyn Union Gas	11.4%	
Yankee Energy Services	10.5%	
New Jersey Natural Resources	2.8%	
J. Makowski Company	2.8%	
Connecticut Natural Gas	2.4%	
New York Power Authority	2.1%	
Long Island Lighting Company	1.0%	33.0%
Tennessee Gas Pipeline Company	13.2%	
ANR Pipelines	9.4%	
CNG Transmission Corp.	9.4%	32.0%

- Iroquois is a strategic link between the largest, most secure gas supply in North America and its largest, fastest growing market. The 370-mile pipeline traverses from the Canadian border through the states of New York and Connecticut, terminating on Long Island. It includes a 26 mile marine crossing of Long Island Sound.

- The pipeline will deliver 576 MMcf/d of western Canadian natural gas to twenty shippers located in six states in the Northeast. Eighty percent of our throughput will be used by local distribution companies. Our twenty shippers have contracted for capacity on a firm basis for twenty years.

- Iroquois is on schedule and we plan to commence deliveries to Northeastern markets on November 1 of this year, just in time for the 1991 winter season. Fifty-eight percent of the gas is destined for markets in New England, while the remaining 42 percent will serve markets in New York State and New Jersey.

- Iroquois has prompted the regional expansion of other pipeline systems in the Northeast. Tennessee Gas Pipeline Company, which will interconnect with Iroquois at Wright, New York, and Shelton, Connecticut, will expand its system to deliver 224 MMcf/d of the gas transported by Iroquois to Massachusetts, Connecticut, Rhode Island and New Hampshire.

- Likewise, the Algonquin Gas Transmission Corporation will be expanding its facilities to deliver gas taken from Iroquois to customers in New York, Massachusetts and Rhode Island. Algonquin interconnects with Iroquois in Brookfield, Connecticut.

- The increased consumption of natural gas in this region will have a direct and significant positive impact on the environment. Sulphur emissions will be reduced by over 75,000 TONS annually, helping to resolve the acid rain problem. In addition, Iroquois will help to reduce the "greenhouse effect", due to the fact that natural gas results in significantly lower carbon dioxide emissions than coal or oil. The

Iroquois project is totally consistent with--and is an essential element of--the newly enacted U.S. clean air legislation.

III THE NORTHEAST MARKET

- The Northeastern United States is more dependent on imported oil than any other geographic segment of this continent. It is unfortunate that it has taken a crisis to bring our dependance on imported oil into focus. Natural gas has become the "hot ticket" in reducing what has become an almost insatiable appetite for imported oil.

- The Iroquois project can help to reduce this dependence by 100,000 barrels PER DAY (30 million barrels per year). I ask that you pay close attention to that statistic. The competition in the Northeast market is natural gas versus oil, not Canadian versus U. S. gas. Despite a recession in the Northeast, the market for natural gas has never been better.

- The potential for natural gas to displace oil in the Northeast is substantial and significant. And the natural gas transported by Iroquois can be used to reduce the use of oil almost immediately through residential and commercial conversions, power plant conversions, and the construction and operation of new gas-fired electrical generating facilities.

- Take, for example, the residential and commercial market. The on-mains saturation level for local gas distribution systems in the Northeast is only about 40 percent. In other words, only four out of every 10 homes or business establishments who have a gas main on their street are actually connected to it. And of that 40%, only about two-thirds of them use gas for space heating.

- If only those homes in the Northeast that are already connected to a gas main were to convert to gas heat, an incremental load of 170 BCF per year would result. That, ironically, is the annual projected throughput of Iroquois.

- Now I am fully aware that the residential and commercial market does not excite a natural gas producer, since it is a very temperature sensitive load. As a matter of fact, it does not excite a natural gas pipeline either, and that is the main reason that growth in the Northeast market has been capacity constrained for many years.

- But there is a new kid on the block, and that is natural gas fired power generation. Just a few years ago, it was a forbidden market. Nearly 60 percent of all oil used to generate electricity in the United States is burned in the Northeast--four times the national average.

- Conversion of oil-fired power plants is an area in which the Iroquois project can fill an immediate need. Projects such as the conversion of Central Hudson Gas & Electric Corporation's Roseton Electric Plant, New England Power Company's Brayton Point Facility and LILCO's

Northport Power Plant, to name only a few, will result in a reduction in oil use by millions of barrels per year--not to mention more stable energy costs.

- There is no doubt that natural gas has become the fuel of choice for new power generation projects. Many of the proposed cogeneration, Independent Power Production and utility projects in New England are proposed to be gas-fired. This is not only by choice; it is also by necessity. In an era where construction of an oil- or coal-fired facility can take more than a decade to complete, gas-fired facilities, with their two to three year lead times, will enable the region to meet its growing need for electrical energy in a timely manner.

- Growth in the residential and commercial sectors, when combined with natural gas fired power generation, makes the Northeast a very attractive market for both producers and pipelines alike.

- But Iroquois will commence operation later this year. Is this market real TODAY?? You bet it is!! Residential and commercial conversions from oil to gas are now taking place so quickly that they are constrained by the availability of crews and equipment, without any artificial incentives of any kind. Connecticut Natural Gas has just contracted to supply Pratt and Whitney 2.5 BCF/year for their jet engine testing facility, replacing jet fuel. Yankee Gas has just announced that they will be extending service to the Groton/New London area of Connecticut, and that incremental load alone will more than account for their supply from Iroquois. And the conversion of Central Hudson's Roseton Generating

Station--which will utilize 100 MMcf/d during the summer months--is on schedule for completion this fall.

IV. CLEARING THE REGULATORY HURDLES

- I noted earlier that the regulatory review of our project has spanned a period of five years. Our first application with the FERC was filed in May of 1986. We now have the somewhat dubious honor of being the most thoroughly reviewed natural gas pipeline in the history of gas pipeline regulation.

- With the issuance of the Corps of Engineers certificate on February 12, we have obtained all requisite regulatory approvals necessary to commence construction.

- Looking back on the process, the following table summarizes the key approvals that we have obtained:

FERC	Certificate of Public Convenience and Necessity	Nov	1990
COE	Corps of Engineers Permit	Feb	1991
NY-PSC	Certificate of Environmental Compatibility and Public Need	Dec	1989
NY-DOS	Coastal Zone Management Consistency	Sept	1990
CSC	Certificate of Environmental Compatibility and Public Need	Oct	1990
CT-DEP	Coastal Zone Management Consistency & Water Quality	Nov	1990

- On this side of the Border, TransCanada Pipelines was actively involved in a hearing (GH-5-89) before the National Energy Board, requesting expansion of their facilities to carry Iroquois' volumes as well as additional Canadian requirements.

- Following favorable decisions last fall with respect to both tolling methodology and this past winter's construction program, the Board last Thursday fully approved the GH-5-89 facilities.

- This decision is great news for Iroquois and its customers, and will ensure that the facilities north of the Border will be constructed in a timely manner.

- In looking back upon the regulatory process, no one can claim that we have not had a thorough and extensive review, and this should place us in excellent shape to move forward with construction without delay.

- I would like to publicly compliment regulatory agencies on both sides of the border for their foresight and perseverance in approving a project that will provide a very important physical and economic linkage between our two countries for many years to come.

V CONSTRUCTION

- Having successfully cleared the regulatory hurdles, we can now focus on the construction of what is the largest pipeline project in the Northeast since the construction of the original Tennessee and Algonquin pipelines.

- As many of you may know, mill space for the supply of line pipe has become a scarce commodity these days. Last fall, Iroquois extended bid invitations to supply pipe to mills in Germany, France, Italy, Brazil, Japan, Canada and the United States.

- Upon acceptance of the FERC certificate in November, Iroquois immediately finalized pipe orders with Stelpipe, Inc., located in Welland, Ontario, and Berg Steel Pipe Corporation, located in Panama City, Florida. Stelpipe and Berg were two of the few mills with the ability to meet both our construction schedule and our exacting technical specifications. The total of both orders is in excess of $125 million. As of this date, about two-thirds of our 30" pipe has been delivered to pipe storage yards along the route.

- Valves and fittings have also been purchased for more than $3.3 million from Canadian and U. S. firms.

- Our 1991 construction program commenced with the award of a $25 million contract for the marine crossing of Long Island Sound to

McDermott International in late February. Construction of the Sound crossing actually commenced on March 4, and will take until mid-July to complete.

- The land portion of the pipeline will be constructed concurrently in six mainland spreads:

Spread 1	Waddington, NY to Croghan, NY	75 miles
Spread 2	Croghan, NY to Manheim, NY (to Mohawk River)	76 miles
Spread 3	Danube, NY to Athens, NY (to Hudson River)	78 miles
Spread 4	Greenport, NY to Dover NY	56 miles
Spread 5	Sherman, CT to Milford, CT	50 miles
Spread 6	Long Island (Northport to South Commack)	9 miles

- In addition, there will be separate spreads for construction of the crossings of the St. Lawrence, Hudson, and Housatonic rivers.

- Bids for the construction of Spreads 1, 2, and 3--covering that portion of the line from the Canadian Border to the Hudson River--closed on April 30, and analysis of the bids received is nearing completion. Award of the construction contracts for these spreads is imminent.

- Bids for Spreads 4 and 5 close in early June. Construction on these spreads will commence later that month.

- The crossing of the Housatonic River, which will be directionally drilled, will take place from June until August. It is anticipated that the crossings of the St. Lawrence and Hudson rivers will start in June and will be completed in October.

- Construction of the land spreads will generally involve a 75-foot right-of-way for construction; a 100-foot right-of-way will be used in agricultural areas where top soil stripping will be performed. Some specialized construction will be required in Spreads 4, 5 and 6 involving rights-of-way less than 75 feet. In most cases our permanent easement will be 50 feet.

- Iroquois initiated the process of obtaining the right-of-way in July 1989 in New York State, and in September 1989 in Connecticut. As part of this effort, field offices have been established in New York in Canton, Utica, Guilderland and Rhinebeck, and in Newtown, Connecticut.

- To date, negotiations have concluded with all 1,586 property owners along the pipeline route. Of that total, over 90% percent have now entered into easement agreements as a result of voluntary negotiations.

- Condemnation proceedings on the remaining 10% have commenced in both states, and are proceeding without difficulty. The judges have, without exception, granted us the right of immediate access for construction. It is safe to say that right-of-way will not be an impediment to our construction schedule.

- By November 1991, Iroquois will have completed all but about 60 miles of the pipeline's construction in New York and Connecticut, and will commence deliveries to its customers. The final connection from

Pleasant Valley, N. Y. to Milford, Connecticut, will be completed by January 1992. At that time, Iroquois will commence direct deliveries to Connecticut and Long Island.

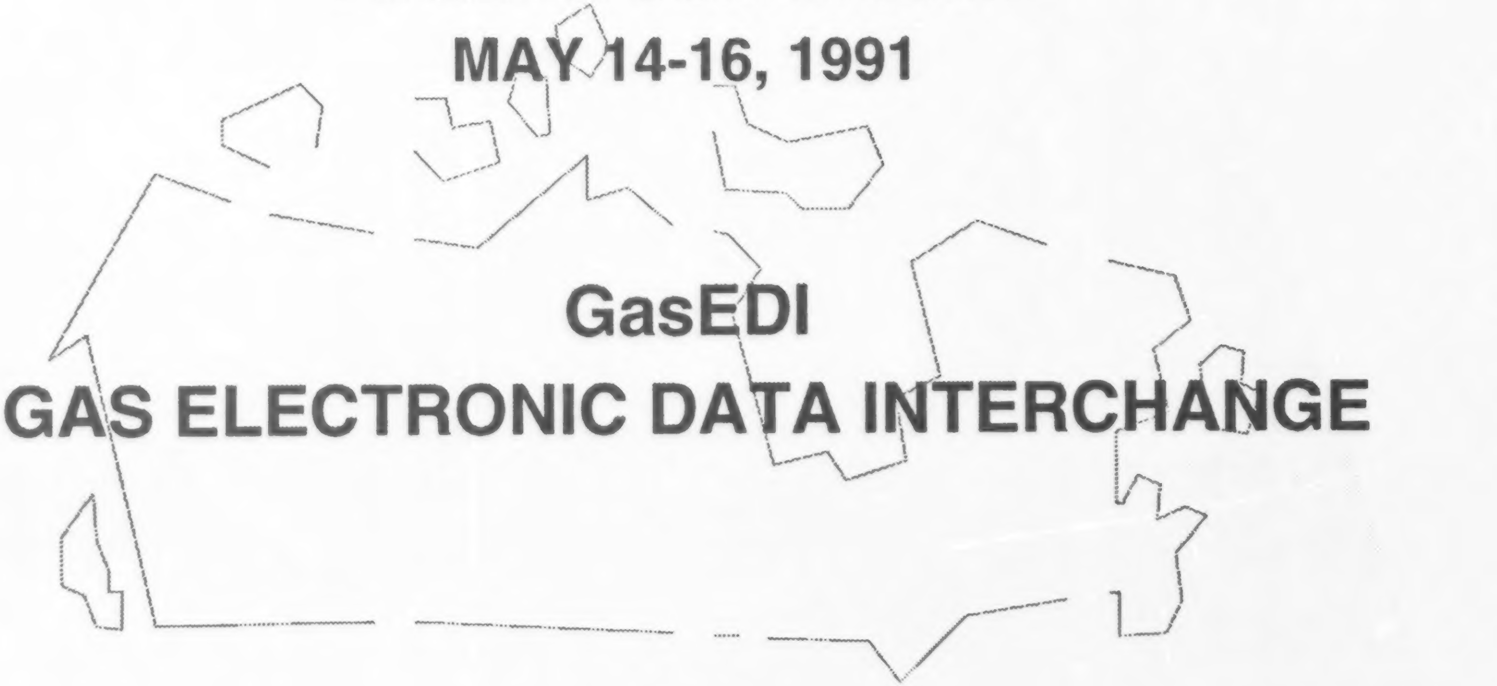
VI. CONCLUSIONS

- Well, there you have it. It has been a long and arduous journey down a very complex regulatory path, but, as you have seen, construction is finally underway.

- We stand ready to reduce the Northeast's reliance on imported oil by 100,000 barrels per day, and to provide a direct and significant positive impact on the environment.

- We are right on target to commence service for the 1991 winter season, and look forward to providing the Northeast with a new, long-term, secure supply of natural gas--the environmental fuel of preference for the 1990s.

CANADIAN PETROLEUM ASSOCIATION
PIPELINE CONFERENCE
MAY 14-16, 1991



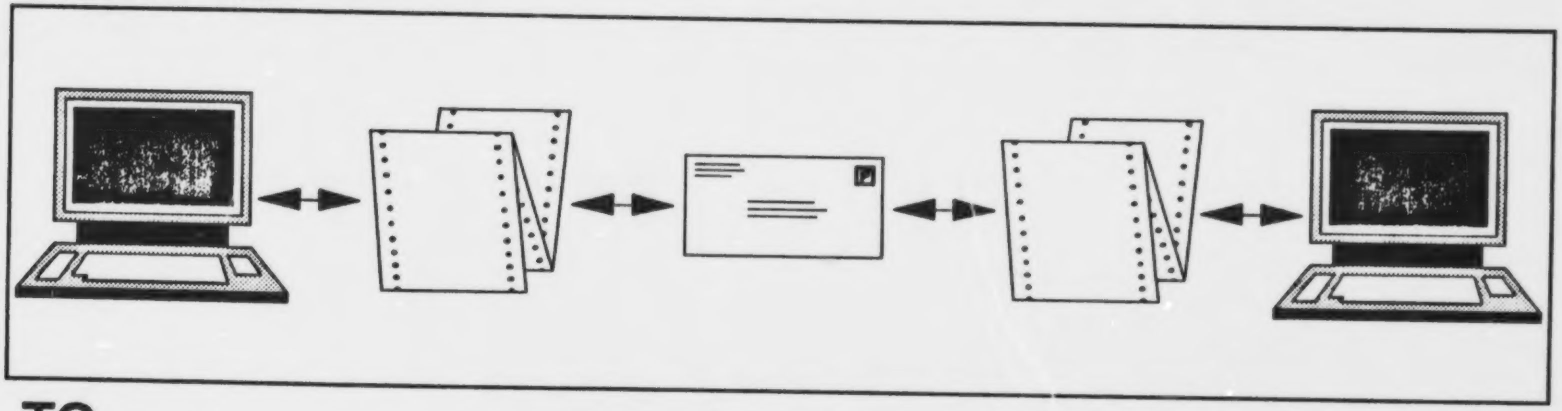
GasEDI
GAS ELECTRONIC DATA INTERCHANGE

Ian S. Anderson

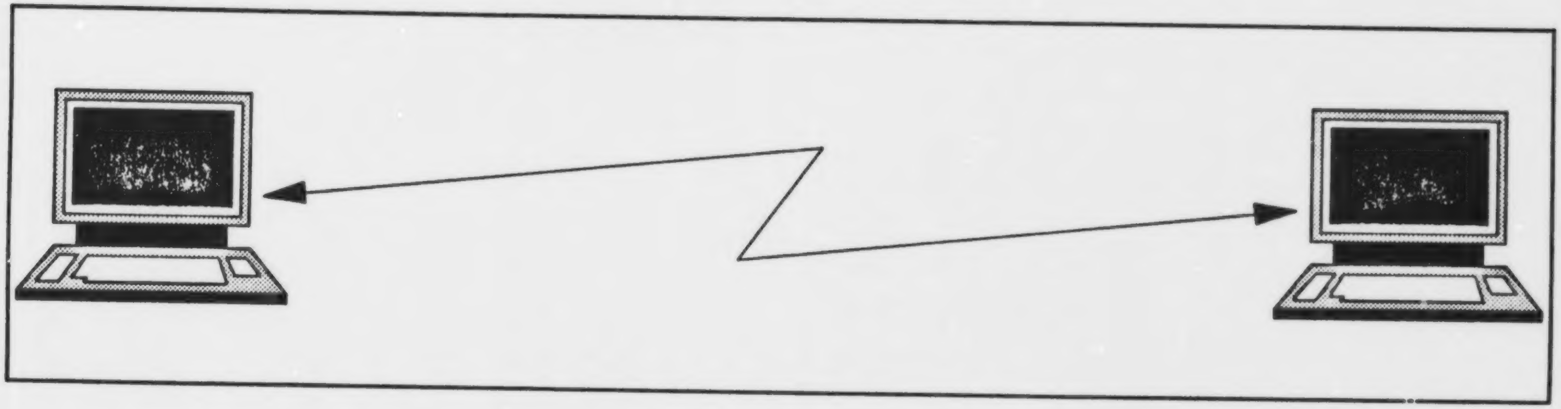
Amoco Canada Petroleum Company Ltd.

GasEDI GOAL

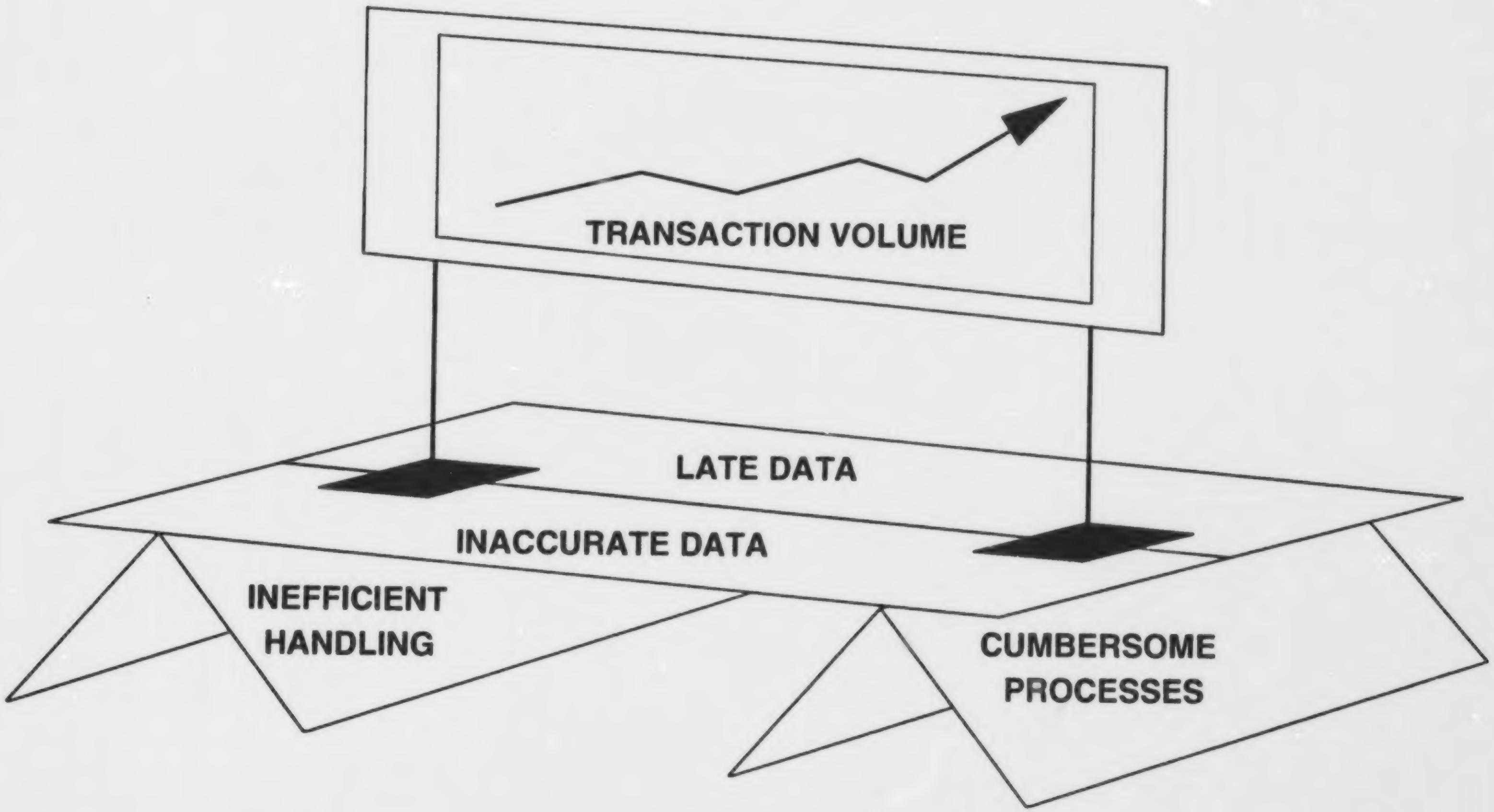
FROM .....



TO .....



WHY GasEDI ?



TRANSACTION VOLUME

LATE DATA

INACCURATE DATA

INEFFICIENT
HANDLING

CUMBERSOME
PROCESSES

CANADIAN GAS INDUSTRY TRANSACTIONS

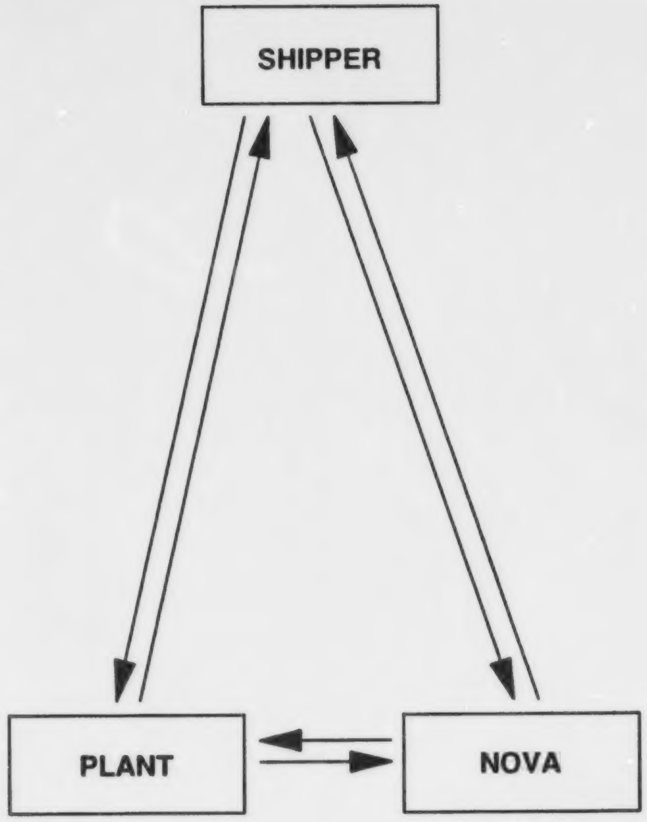
TRANSACTION	#/MONTH
Contracts	Unknown
Nominations	>50,000
Confirmations	>50,000
Daily Reports	>60,000
Metered Volume Statements	>30,000
Allocation Statements	>25,000
Invoices	<25,000
Payments	>25,000
Regulatory Reports	Several Thousand
TOTAL	>265,000

NOMINATIONS

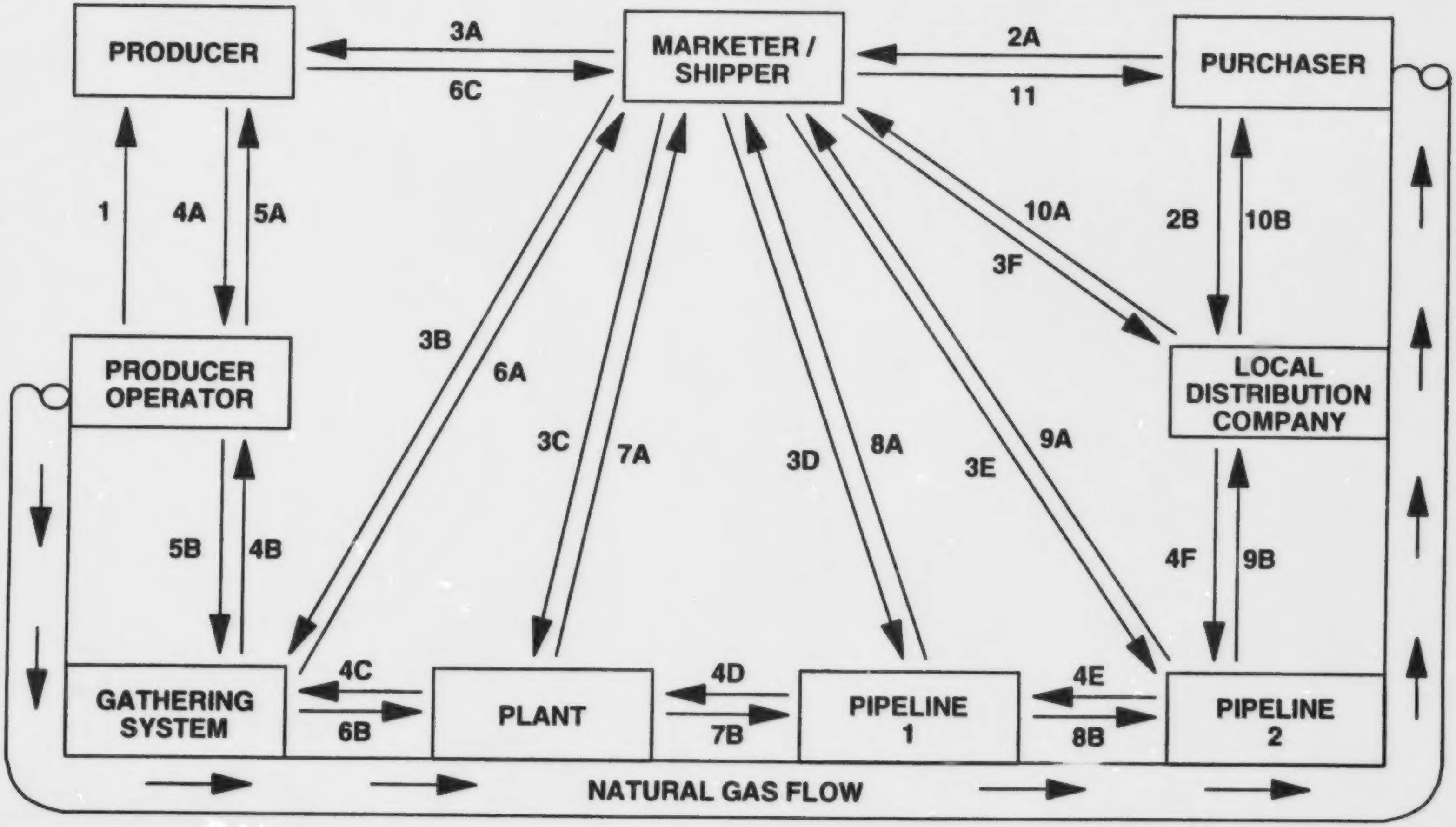
SHIPPER

NOVA

NOMINATIONS & CONFIRMATIONS


SHIPPER
PLANT
NOVA

NOMINATIONS & CONFIRMATIONS


PRODUCER

MARKETER / SHIPPER

PURCHASER

PRODUCER OPERATOR

LOCAL DISTRIBUTION COMPANY

GATHERING SYSTEM

PLANT

PIPELINE 1

PIPELINE 2

NATURAL GAS FLOW

3A
6C
2A
11
1
4A
5A
10A
3F
2B
10B
3B
6A
3C
7A
3D
8A
3E
9A
5B
4B
4F
9B
4C
6B
4D
7B
4E
8B

BENEFITS

- **REDUCED ADMINISTRATION COSTS**

  Less Effort; More Accurate; Clear Audit Trail

- **IMPROVED MANAGEMENT PROCESSES**

  Eliminate/Streamline; More Focused Analyses;
  Improved Cash Flow; Information Sharing;
  Stronger Business Relationships

- **INCREASED FACILITY UTILIZATION**

  More Sales; Lower Unit Costs;
  Better By-Product Management

COSTS

- MANPOWER

  Champion; Implementation Team; Operations; Training

- SOFTWARE

  Data Management; Business Management; Setup

- HARDWARE

  PC; Mini; Mainframe

- COMMUNICATIONS / SUPPORT

  Telecommunications; Value Added Network

ISSUES

- **BUSINESS**

  Principles & Procedures; Timing of Information Flows; Business Management Software; Industry Concurrence

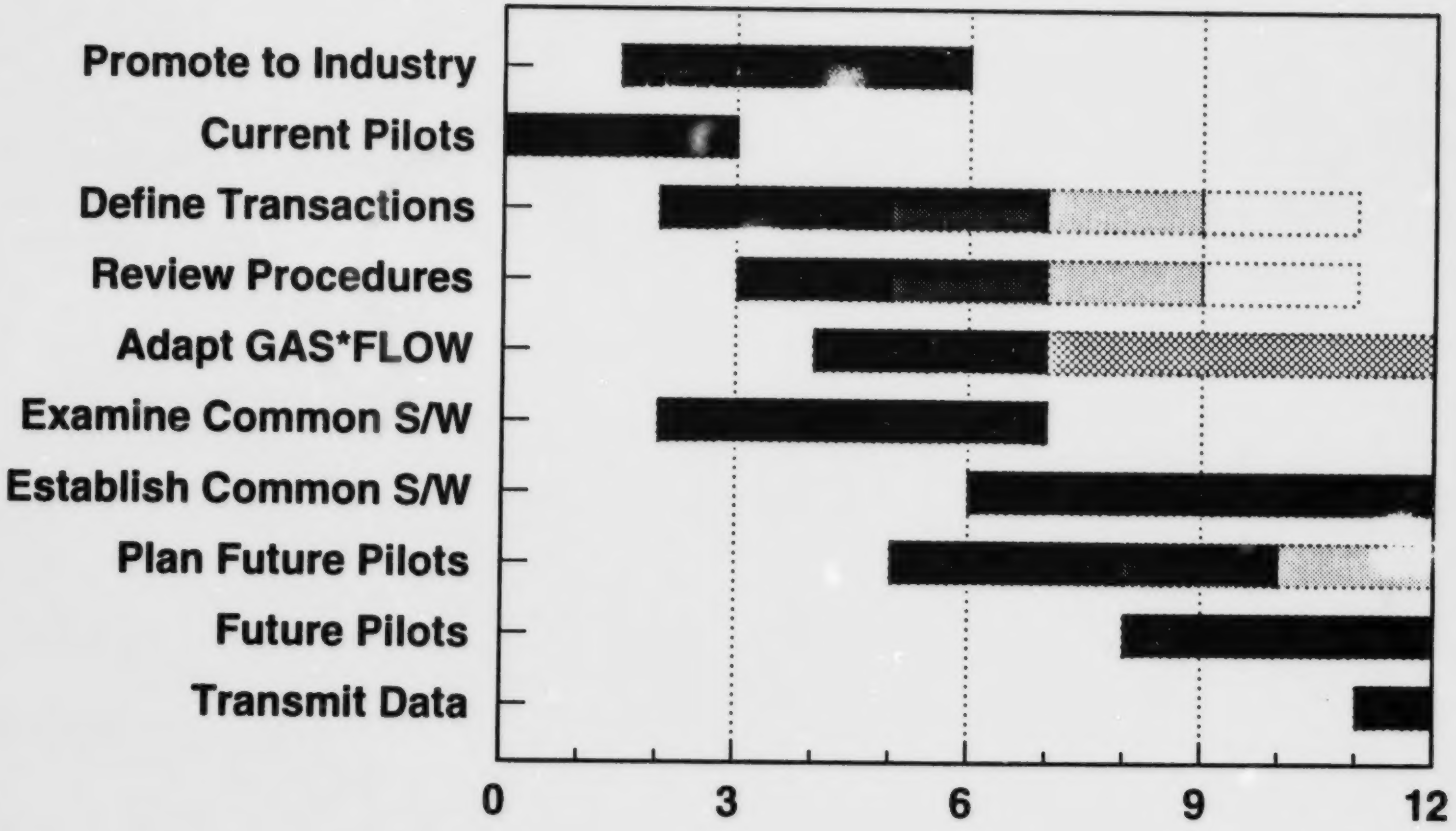
- **STANDARDS**

  Adaptation of GAS*FLOW; Other EDI Applications

- **TECHNICAL**

  EDI Software; Communications

DEVELOPMENT - 1991 TIMELINE



CANADIAN PETROLEUM ASSOCIATION

CRUDE OIL MOVEMENTS ELECTRONIC DATA INTERCHANGE

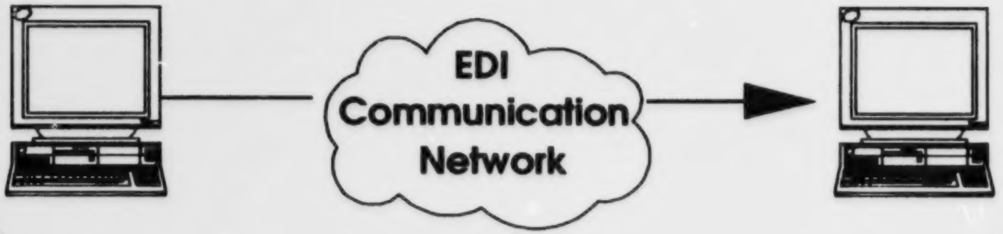
(EDI)

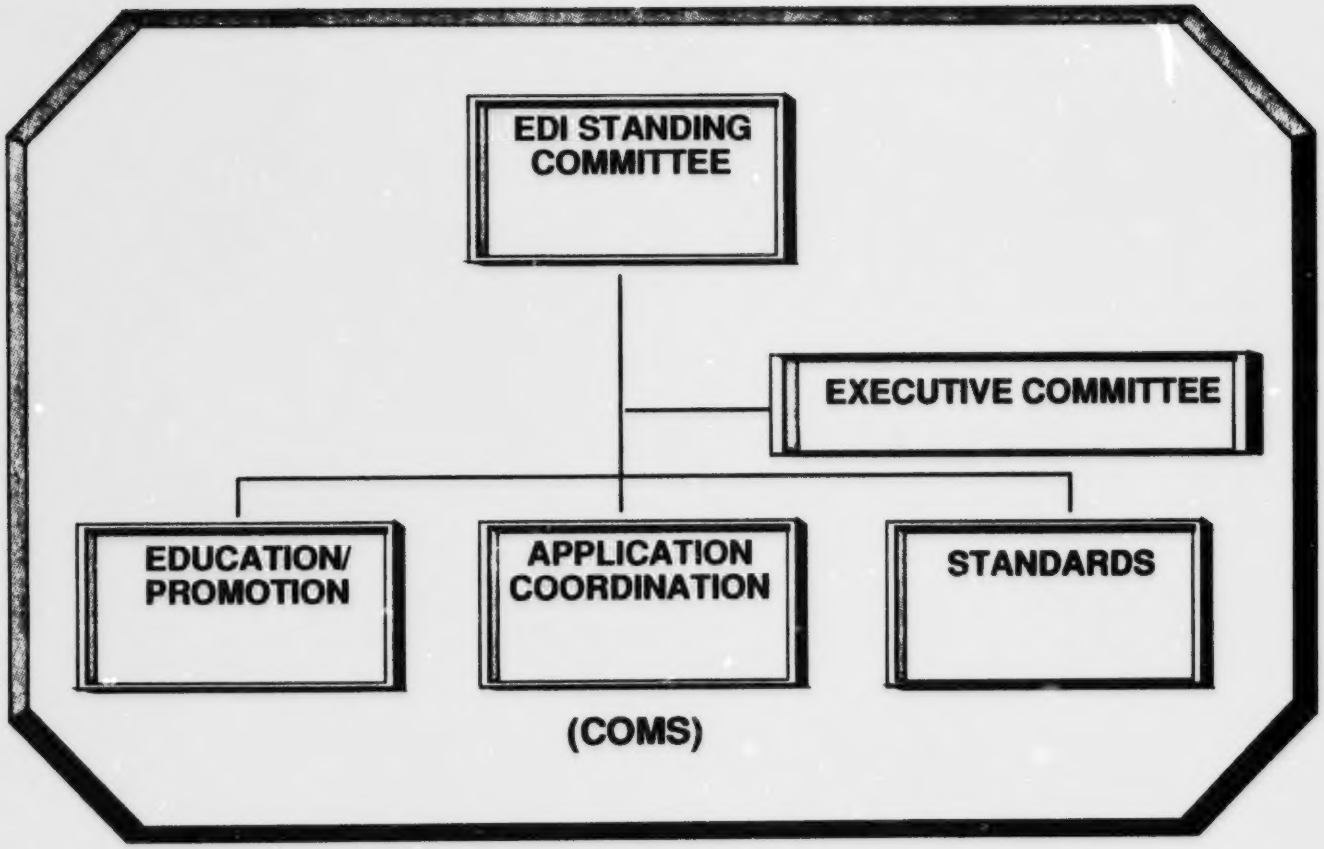
Jerry Godin

Pipeline Conference
May 15 - 16, 1991

WHAT IS EDI ?

The Intercompany Electronic Transmission of Business Transactions in a Standard Format


EDI
Communication
Network



EDI STANDING COMMITTEE

EXECUTIVE COMMITTEE

EDUCATION/ PROMOTION

APPLICATION COORDINATION

STANDARDS

(COMS)

PARTICIPATING COMPANIES

Alberta Petroleum Marketing Commission
Amoco Canada Petroleum Company Ltd.
Federated Pipe Lines Ltd.
Gibson Petroleum Company Limited
Imperial Oil Limited
Interprovincial Pipe Line Company
Peace Pipe Line Ltd.
Petro-Canada
Shell Canada Limited
Trans Mountain Pipe Line Company Ltd.

PILOT PROJECT DOCUMENTS

Forecast of Deliveries to Shippers
Forecast of Deliveries to Pipelines

Notice of Shipment

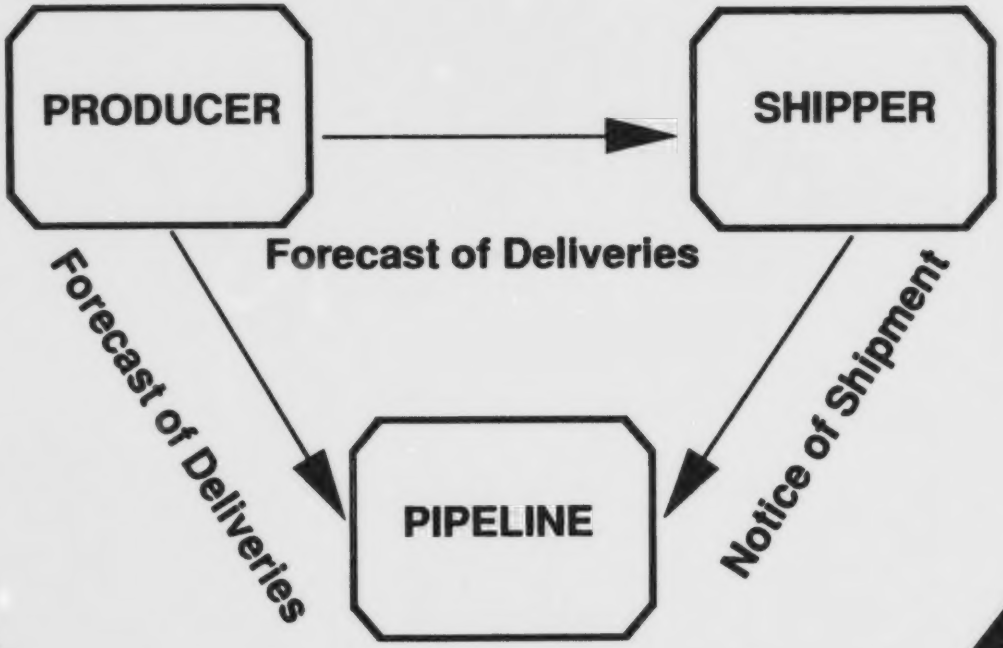
Draft Shipper's Balance

Shipper's Balance

Tariff Invoice

Equalization Statement

DOCUMENT EXCHANGES
(Example)



PRODUCER

SHIPPER

Forecast of Deliveries

Forecast of Deliveries

Notice of Shipment

PIPELINE

INDUSTRY STANDARDS

- Shippers and Pipeline Operators
  - Dun & Bradstreet Code
- Product Identification
  - Petroleum Industry Data Exchange (PIDX)
- Battery Operator
  - ERCB
- Location ID
  - ERCB & Legal Description (LSD)
- Terminals & Pipeline
  - Government Agency (APMC or other)

PROJECT STATUS

December 1989 thru May 1990
  Documentation for Business Standards

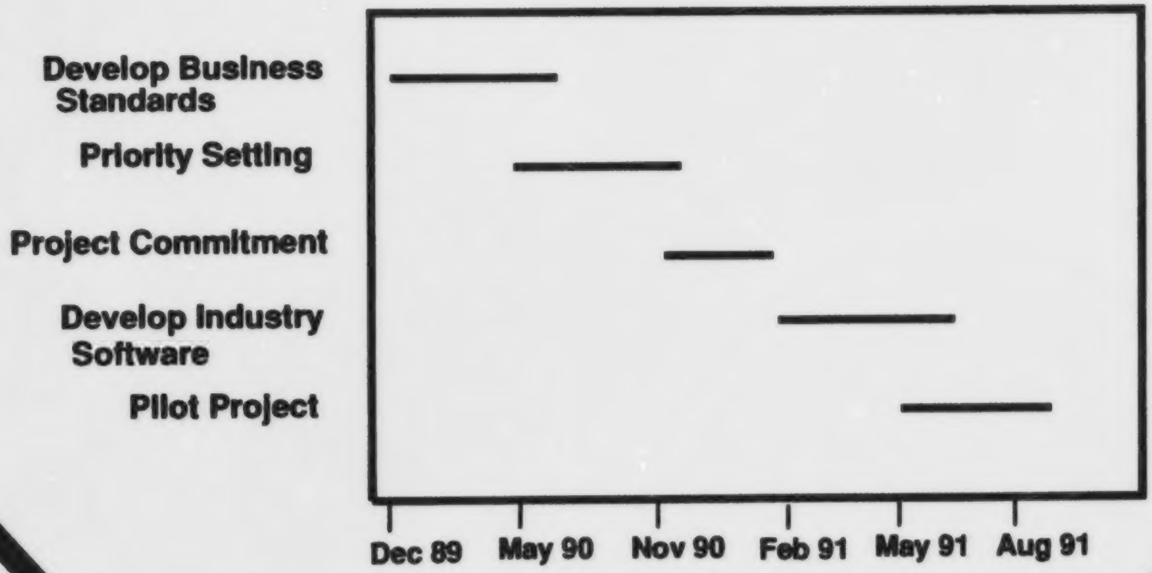
May 1990 thru November 1990
  Industry Survey for Priority Setting

November 1990 thru February 1991
  Pilot Project Commitment

February 1991 thru June 1991
  Development of Industry Software

May 1991 thru August 1991
  Pilot Project on 7 Documents

PROJECT STATUS



THE CHANGING WORKFORCE:

CHALLENGES FACING THE PIPELINE INDUSTRY

Barbara Tate
Manager, Human Resources
NOVA Corporation of Alberta
Alberta Gas Transmission Division
May, 1991

To be competitive in the labour market and business environment, the management of human resources requires a high level of commitment in understanding and adjusting to workforce trends. This requirement arises out of three key human resources issues affecting the future of North American businesses: changing demographics, changing attitudes toward work and changing skill needs.

1. CHANGING DEMOGRAPHICS

The population in North America and Canada specifically, is aging and the birthrate is steadily declining. Due to these factors, the composition of the workforce is changing. The key implication of this change for the pipeline industry is that we must build an environment conducive to attracting, retaining and developing required skills to meet long term business needs.

Birthrates in Canada are declining steadily and have been below replacement level for the past 20 years. The following projections are based on this declining birthrate:

- 16% decrease in 25-34 year old workforce by 2001.
- 9% increase in 45+ population by 2001.
- 100% more people age 55+ by 2050.
- life expectancy will increase from 75 to 81 by 2080.
- 15% decrease in workforce participation of those aged 55 to 65 in last 30 years.

There will continue to be fewer young people entering the workforce while at the same time the workforce is aging and retiring earlier. There will be less people available from the traditional workforce.

The composition of the available workforce is also changing. Ninety percent of the increase in the workforce over the last 10 years can be attributed to women. In Alberta, the number of women in the workforce rose from 57.1% in 1980 to 63.9% in 1988. This was the largest change in Canada. By the year 2000, only 20% of the new labour force entrants will be white males. Other segments of the population will also become more prevalent in the available workforce. Natives have the highest fertility rate of any group and are projected to comprise 20% of the available new entrants to the labour market by the year 2000. However, 23% are currently unemployed. Visible minorities are presently 5.6% of the population. By the year 2000, 42% of new entrants to the labour force will be non-whites or immigrants. The workplace of the future will be one characterized by diversity.

Immigration is also impacting workforce demographics. Currently Canada's immigration policy is expansionist, however, to achieve 1% population growth, quotas must be raised by an additional 275,000 people per year. Trends in groups immigrating to Canada are also changing. In the past 10 years, there has been a significant decrease in European immigrants and a corresponding increase in Asian immigrants. In addition, more Canadians and immigrants are living in urban centres than before. By 2001, 86.2% of Alberta's population will reside in urban areas compared to 73.5% in 1971. This trend may result in difficulty in attracting the labour force that is needed in rural locations for construction and operations. However, while immigration is contributing to the diversity of the workforce, it is not increasing population growth enough to counter demographic trends.

The central challenge for managing human resources in North America is building an environment that will facilitate attracting, retaining and developing the skills required to meet long term business needs. The declining birthrate is resulting in a marked decline in growth of the labour force. Coupled with an aging population, this will produce a labour force shortage. Groups who presently face constraints when entering the labour force such as lack of education and discrimination will need to be given greater opportunities for participation. These groups will comprise a major portion of the available workforce by the year 2000, and represent a significant resource that has yet to be fully utilized. This untapped resource will include women, immigrants, non-whites, and older employees in general.

Business must be proactive in addressing the implications arising from changing demographics. Outreach recruiting to access diverse groups, enhancement of existing recruitment programs to attract employees and valuing diversity training are some initiatives that will enable businesses to continue to attract and retain required skills.

2. CHANGING ATTITUDES TOWARD WORK

Employee values are changing. There is a change in the traditional employer/employee relationship, sources of employee motivation, and an emphasis on quality of life.

The employer/employee relationship is changing. In the past, organizations were more stable and required highly defined skills and abilities from employees. Their primary concern was increasing productivity. Now, with global competition and de-regulation, organizations are forced to be more dynamic and require a variety of skill sets, including creativity, communication and innovation. This new operating reality has emerged as organizations compete based on factors other than productivity, factors such as quality of product and service and customer responsiveness.

The emphasis has changed from managing technology to effective management of people. Therefore, the structure and style of organizations must be more aggressive in promoting employee participation and training. In addition, employees in today's workforce want to develop new skills and make a positive contribution to the company through meaningful work that involves creativity, responsibility and authority.

With changing attitudes and the trend toward flatter organizational structures, today's workers are demanding pay for performance, job enrichment and a variety of non-monetary recognition systems. Job enrichment includes cross-training and job rotation, lateral movement, special project assignments, sabbaticals and educational leaves. Another aspect of the employer/employee relationship that is undergoing a change is company loyalty. Employees are becoming more loyal to their careers. Although there is still company loyalty for the duration of their employment, it may be overridden by personal commitment to career development. This increasing need for career independence is resulting in higher employee mobility between organizations. A recent Canadian poll concluded that 39% of employees intend to stay with the same employer for five years or less.

There is also a new value among today's employees that focuses on the importance of leisure time, family and quality of life. Demands for daycare, eldercare, more time off from work for maternity and paternity leaves, child-rearing duties and other pursuits are already increasing. Interest in part-time, flexible, and stay-at-home jobs is also increasing and presently, over 20% of the Canadian workforce are in alternative work arrangements. Studies have shown marked increase in employee's productivity when entering a voluntary alternative work arrangement and increasing demand for these alternatives. In addition, employees are increasingly reluctant to accept career moves that may affect quality of life, such as a transfer to a rural location.

In order to provide an attractive workplace, businesses must now adapt to continually changing attitudes and values as new generations enter the workforce. This presents some unique challenges for the pipeline industry. Adaptation to employees changing attitudes may be more difficult to achieve in the field environment than in an urban environment due to different operating realities. Businesses must begin implementing innovative work arrangements, recognition systems, career development and other such programs in order to address changing attitudes and values.

3. CHANGING SKILL NEEDS

Changing skill needs and demographic trends are resulting in a reduction of the availability of qualified employees, producing a skills gap. Continual technological advances require frequent retraining and upgrading of the existing workforce.

Attaining and maintaining basic skills, education, specialized training and interdisciplinary skills are crucial for new entrants as well as existing employees in order to meet business needs.

It is becoming increasingly difficult to find young workers with the required skills and knowledge. There is a trend toward more knowledge-based jobs which require increased specialized skills and a variety of interdisciplinary skills. The education required for jobs is increasing. The current average is 12.8 years and by the year 2000 it is projected that almost half of positions will require more than 17 years education. However, almost 60% of workers now in the labour force have no more than secondary schooling, and 24% of adult Canadians are functionally illiterate. Canada produces less university and college graduates than are required in the work-force and there is declining enrolment in sciences, engineering and technical fields. In addition, government funding to post-secondary institutions is decreasing.

Skill and knowledge requirements for individuals presently in the workforce due to continuous technological advances and requirements for more interdisciplinary skills necessitate constant retraining and upgrading. Unemployment is often an indicator of those who are not adapting to these changes. In the last few years, more than half of employees laid off did not have the required skills and education for their changing role. Changing demographics and immigration will also impact the need for more interdisciplinary skills, particularly communication and English as a second language.

Many North American businesses, including pipeline companies, are already experiencing the gap between the skills and education of the available work pool and industry requirements. Recruiting qualified candidates in engineering, computer science and technical fields is becoming more difficult. In addition, the increased need for more technical education, particulary in the field, will affect ability to recruit. The skills gap should be addressed through training and development programs and liaison with educational and government institutions. This will help ensure business has the skills it requires in the future.

CONCLUSION

The changing workforce presents many challenges for the pipeline industry. Recognition of the right opportunities for your company, along with flexibility and effective management of change will enable the pipeline industry to remain competitive in the labour market and business environment.

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THE CHANGING WORKFORCE:

CHALLENGES FACING THE PIPELINE INDUSTRY

BARBARA L. TATE

MAY 1991

NOVA

9428

THE CHANGING WORKFORCE

To be competitive in the labour market and business environment, the management of human resources requires a high level of commitment in understanding and adjusting to workforce trends.

KEY ISSUES:

1. Changing Demographics

2. Changing Attitudes Towards Work

3. Changing Skill Needs

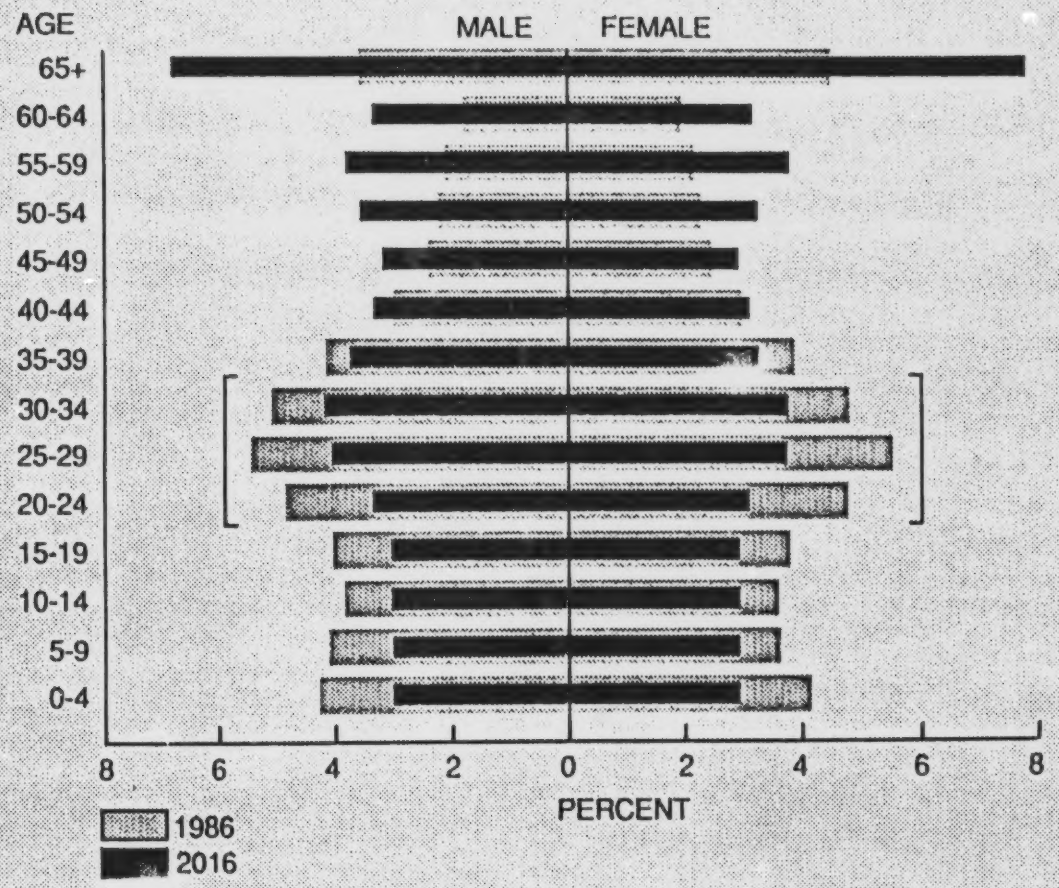
1. CHANGING DEMOGRAPHICS

The composition of the workforce is changing dramatically as a result of a number of factors:

- Declining Birthrate
- Aging Population
- Diverse Workforce
- Immigration
- Urbanization

DECLINING BIRTHRATE AND AGING POPULATION

AGE-SEX DISTRIBUTION OF THE POPULATION IN CANADA



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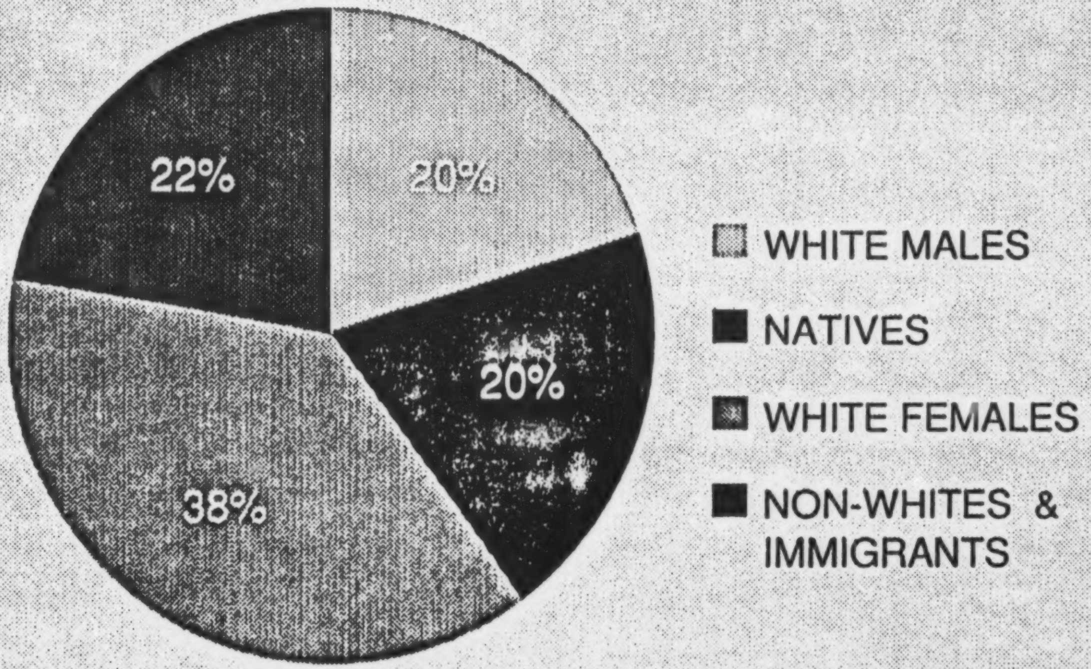
DIVERSE WORKFORCE

AVAILABLE NEW ENTRANTS TO THE CANADIAN WORKFORCE (2000)



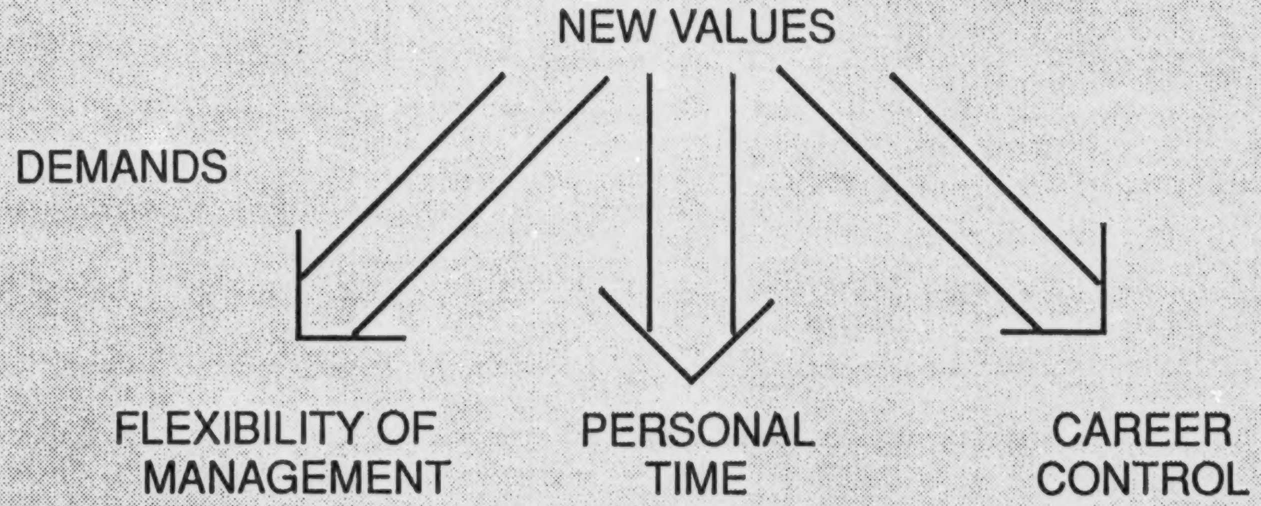
CHANGING DEMOGRAPHICS – CONCLUSIONS AND IMPLICATIONS

TREND:	Decreased availability of traditional workforce
CONCLUSION:	Utilize a more diverse workforce
IMPLICATION:	Attract, retain, develop diverse workforce

2. CHANGING ATTITUDES TOWARDS WORK

Employees' values are changing

TRADITIONAL:	NEW:
• Self-denial	• Self-fulfilment
• Higher standard of living	• Better quality of life
• Traditional sex roles	• Blurring of sex roles
• Accepted definition of success	• Individual definition of success
• Faith in industry and institutions	• Self-reliance
• Live to work	• Work to live
• Traditional family	• Alternative family
• Getting ahead	• Getting free
• Getting secure	• Getting balanced



NEW VALUES

DEMANDS

FLEXIBILITY OF
MANAGEMENT

PERSONAL
TIME

CAREER
CONTROL

CHANGING ATTITUDES TOWARDS WORK – CONCLUSIONS AND IMPLICATIONS

TREND:	Changing needs and values
CONCLUSION:	Accommodate changing employee needs and values to attract, develop and retain
IMPLICATION:	Change in management structure and attitude

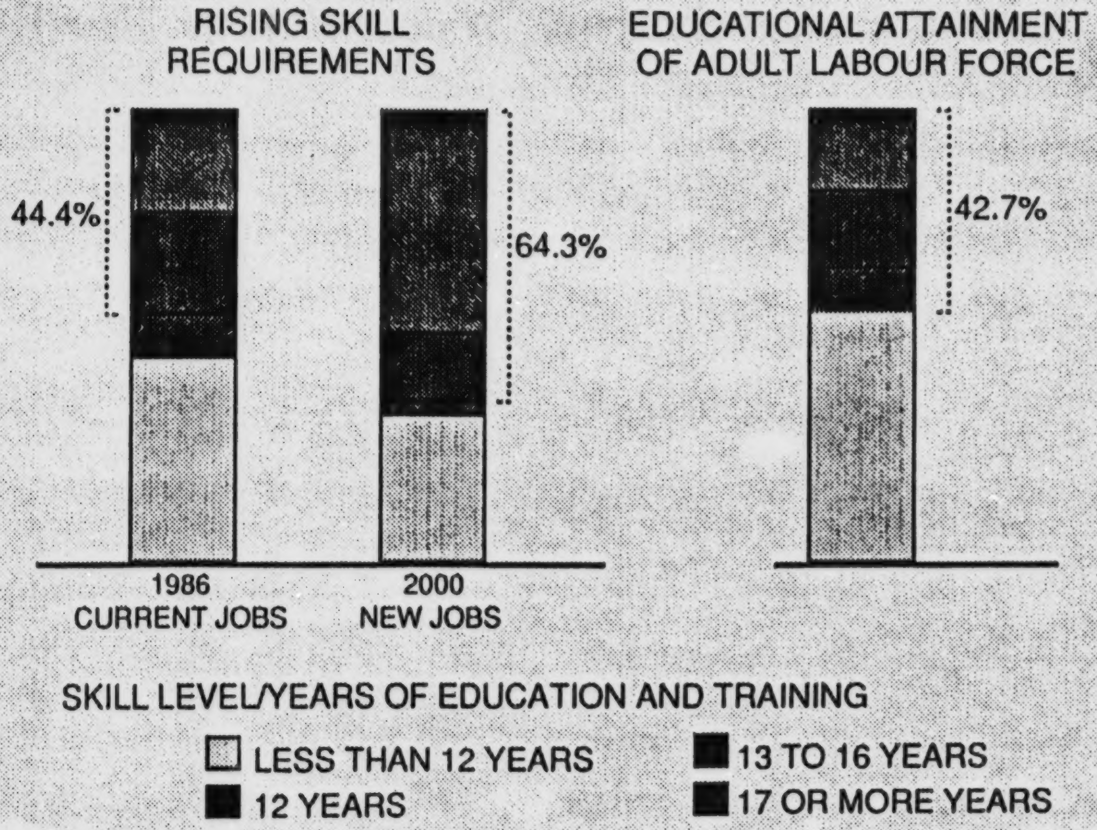
3. CHANGING SKILL NEEDS

There is a gap between business needs and skills available due to:

- Demographics
- Education System
- Technological Advances
- Emphasis on Interpersonal Skills

SKILLS GAP

Requirements for training are increasing while at the same time Canada is producing fewer qualified people than are required.



CHANGING SKILL NEEDS – CONCLUSIONS AND IMPLICATIONS

TREND: Increasing skills gap

CONCLUSION: Difficulty finding necessary skills in future workforce

IMPLICATION: Increased commitment to training and education and reassessment of skill requirements

CHALLENGES FOR THE PIPELINE INDUSTRY

- Flexibility
- Change in management style
- Valuing diversity
- Outreach recruiting
- Enhance existing recruiting programs
- Alternative work arrangements
- Innovative recognition systems
- Career development programs
- Needs assessment, development and implementation of training programs
- Liaison with educational and government institutions

GLOBAL CLIMATE CHANGE

AND WHAT THE CPA IS DOING

May 1991

CPA POSITION:

Where we're part of the problem, we want to be part of the solution

OBJECTIVES

- Have CPA contribute to Canadian decision-making
- To help Canada reach the right policy and direction decisions
- Timely input and participation
- Promote effective actions within our member companies

CRITERIA

- Cost effectiveness (effective resource allocation)
- Credibility
- Maintain reasonable profile
- Contribute to solutions

Examples of CPA Committee Activities

1989

UNDERSTANDING THE ISSUE

- Committee formed and working
- Comparative inventory conducted
- Review control options information
- Submission made to Federal Standing Committee on the Environment

GREENHOUSE EFFECT
INDUSTRY PERSPECTIVES

THE KNOWNS

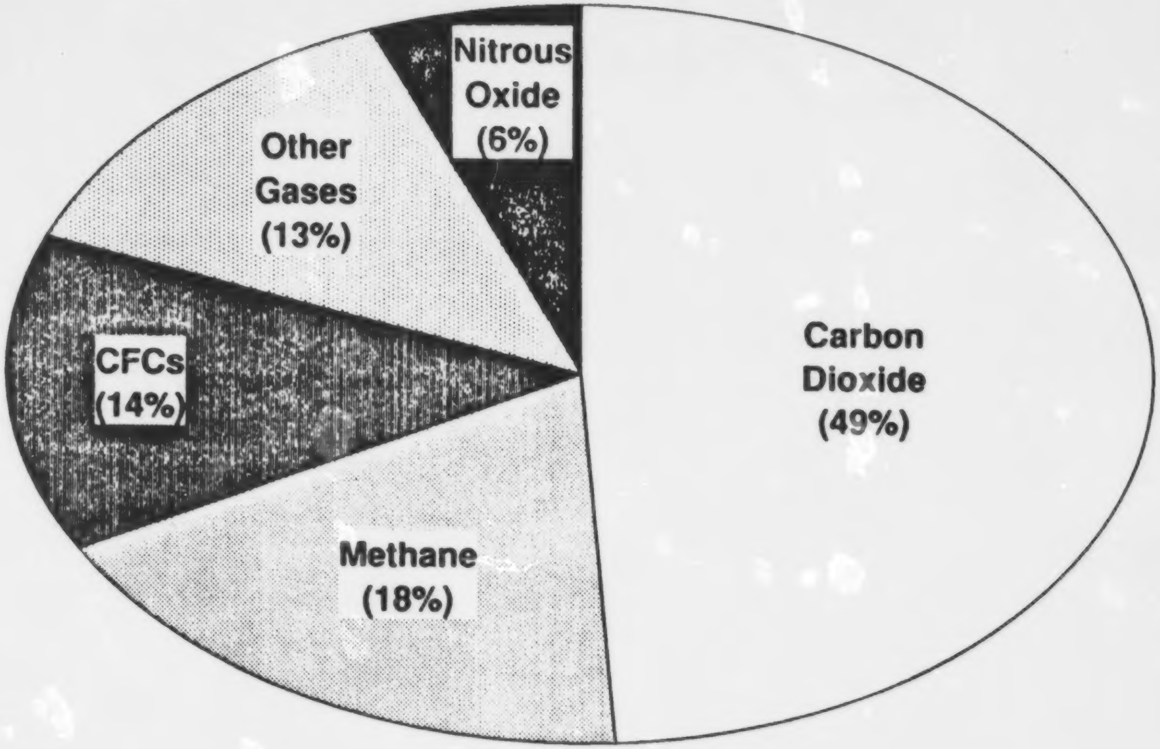
- Greenhouse effect is real
    - responsible for life on earth
- Man-created greenhouse gases are increasing in the atmosphere
    - measured concentrations
- Indications of warming
    - warmest years recently

GREENHOUSE EFFECT
INDUSTRY PERSPECTIVES
(cont'd)

THE UNCERTAINTIES

- Models predict varied impacts
  - from less than 1 to more than 4 degrees
- Regional effects may vary widely
- Uncertainties surround; impact of oceans, water vapour (clouds) in atmosphere and other natural mechanisms
- Overall projected impacts range from modest to catastrophic

GREENHOUSE GAS CULPRITS*



* Estimates of anthropogenic emissions to Greenhouse Effect
Source: World Resources Institute

BACKGROUND

Greenhouse Gas	Projected Contribution by 2020	Manmade Source	Contribution from Oil and Gas Activities
CO2	49	- Fossil fuel - Deforestation	Directly - Medium-Low Indirectly - Medium-High
CH4	18	- Biological activity - Animals - Coal production - Fuel losses	Small
CFCs	14	- Refrigerants - Aerosols - Foams	Minimal
N20	6	- Fertilizers - Burning fossil fuels	Minimal
Others (Ozone)	13	- Photochemical reactions	Directly - Small Indirectly - Medium-Large

--- CO2 is the greenhouse gas issue for oil and gas ---

A PROPOSED STRATEGY

Key points from CPA submission to the Federal Standing Committee on Environment - Canada should:

- strongly support CONSERVATION activities
  - do things that make sense in their own right
- increase PREPARATION
  - identify potential impacts and ensure mitigation measures are available
- improve scientific UNDERSTANDING
  - participate globally
  - conduct Canadian specific research
- promote EDUCATION
  - required by all sectors of society

Examples of CPA Committee Activities

1990

UNDERSTANDING OUR CONTRIBUTION & OPTIONS

- Presented CPA position on global climate change to Federal Standing Committee on the Environment
- Held workshop on inventories
- Commissioned inventory study (VOC/CH4) CO_2, NO, SO_2
- Endorsed U of C ethics and global warming study
- Selected science advisor and issued report on global warming
- Co-sponsor of CO2 disposal study
- Co-funded study on economic instruments related to SO2

AIR ISSUES
RANGE OF ENVIRONMENTAL IMPACTS

ENVIRONMENTAL ISSUE	POLLUTANTS	GLOBAL	CONTI-NENTAL	LOCAL/ REGIONAL
1. Greenhouse Effect	CO2, CH4, N2O, CFCs	▨		
2. Ozone Depletion	CFCs, N2O, Halon	▨		
3. Deforestation	CO2	▨	▨	▨
4. Acid Rain	SO2, NOx		▨	▨
5. Ground-Level Air Pollution/ Air Quality	CO, SO2, NOx, O3, VOCs, Pb, HAPs Heavy Metals, Particulates			▨
6. Nuisance	Noise, dust, traffic, light, odour			▨

Examples of CPA Committee Activities

1991

BEING PART OF THE SOLUTION

- Co-sponsored conference on global climate change
- Validation of CH4/VOC inventory study
- Control option workshops planned:
  - CO2
  - CH4/VOC
- Integrated trade-off study planned:
  - CO2/NOx/SO2/others
- Further work on economic instruments
- Global warming science update
- Ongoing efforts on air issues proceeding under following headings:
  - science
  - inventories
  - control options/costs
  - tracking and reporting
  - forecasting
  - applicability of economic instruments

RESULTS

- We have made a start but this is a long-term undertaking
- Examples of results to date:
  - CO2 control options study show presently cost-effective energy use reductions to be less than 10%
  - Economic instrument study provides valuable insight into benefits of permit trading for SO2 control in Alberta
  - Scientific assessment has provided basis for discussion and understanding
  - CH4 emission inventory work has identified key potential sources for control

SOME KEY ISSUES

- ESTABLISH PRIORITIES
  - making best use of limited resources
- MAINTAIN COMPETITIVENESS
  - ensuring affordability
- REDUCE ENVIRONMENTAL IMPACT
  - solutions which provide real benefits
- SELECT NO REGRET DECISIONS
  - actions which make sense in their own right

PIPELINE GREENHOUSE GAS ISSUES

THE ISSUE

- Stabilization of atmospheric greenhouse gas concentrations by 200? at 1990 levels

GASES OF CONCERN

- CO2, CH4, N2O, NOx (indirectly)

THE POTENTIAL IMPACTS

- Same carbon sold in 2000 as in 1990
- Natural gas sales increase
- Conservation and efficiency improvements in delivery system required
- Low NOx drivers needed
- Increased inspection, maintenance directed at reducing fugitive emissions
- Additional equipment and/or changed operating procedures to avoid venting

"THE FUTURE SURE AIN'T

WHAT IT USED TO BE."

EMERGING TRENDS IN ENVIRONMENTAL LAW

Scott R. Miller*

Summary: Public Concern over the environment has led to new legislation and a trend toward legislative and jurisdictional competition between the Federal and Provincial Governments in relation to the environment. Common elements within the new legislation such as environmental impact assessment, director and officer liability, increasing obligations and fines, reporting requirements and profit stripping are discussed in this paper. A listing of current environmental legislation is attached.

Emerging Trends in Environmental Law

The area of environmental law has undergone a substantial change over the last five years. Rising public concern over the state of the environment has strengthened new legislative action and enhanced enforcement of existing laws in relation to the environment. Environmental problems such as the Exxon Valdez incident, the PCB fire at St. Basile-le-Grand and local concerns such as the leaking of creosote into the Bow River have galvanized public concern and encouraged governmental response. In the face of sustained public interest in the environment the government has responded by increasing existing enforcement and by passing new legislation which seeks to control and curtail environmental damage.

Increased public interest has resulted directly in the passage of a variety of new environmental laws and the imminent introduction of others. The ***Canadian Environmental Protection Act***, ("CEPA"), the Ontario ***Environmental Protection***

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Act, ("OEPA") and the proposed Alberta ***Environmental Protection and Enhancement Act*** ("AEPEA") are examples of legislation specifically dealing with environmental concerns that have been implemented principally as a result of public concern to control direct effects of environmental pollution. On the planning side of environmental control ancillary legislation, such as the proposed ***Canadian Environmental Assessment Act*** ("CEAA") will deal with environmental assessments for major projects before they are implemented. As well, very broad laws of general application such as the proposed environmental Bill of Rights which is presently being contemplated by the legislature in Ontario, will extend to the public legal rights in the quality of the environment. All of this new legislation results directly from governments recognition of public interest concerning environmental matters and affects the actions of all parties who use the environment.

Despite the fact that most of this legislation has been drafted in order to meet the concerns of different jurisdictions the fact is that most of this new legislation contains similar elements. For example, most of the new legislation includes:

- increased investigative and search powers;
- mandatory spill reporting;
- increased fines and penalties for violations;
- direct responsibility for environmental liabilities by officers, directors and employees;
- profit stripping provisions and provisions designed to recover investigative costs; as well as,
- an enhanced role in environmental protection and prosecution by the public.

As well as these obvious common denominators public concern over the environment has also resulted in less obvious changes such as increased competition between the federal and provincial governments to secure jurisdiction over the environment, increased attention to environmental impact assessment processes and hearings, increased public access to information concerning the environment and increased and creative use of existing regulatory powers and common law rights by individuals in order to regulate or enforce environmental action.

The general legal trend observed over the last five years indicates a substantial increase in direct regulation in this area, however, it also appears evident that further action will be forthcoming. Both the legislative response of government and the common law response of the courts represents challenges and changes for both the public and industry.

Federal and Provincial Interest in the Environment

Driven by public interest both the Federal and Provincial governments have acted to extend their jurisdiction over environmental matters. Attention to environmental matters and new resulting legislation has led to increased, and often overlapping, laws. In the absence of a co-ordinated plan industry and the public are faced with a variety of laws from both levels of government rather than dealing with the environment on the basis of a "one window approach".

The competition to secure jurisdiction over the environment arises not only due to a response to public interest but is also due to the fact that the division of legislative powers between the federal parliament and the provincial legislatures is not clear in the case of the environment. The basic division of powers set out in the ***British North America Act*** ("BNA"), 1867 which was constitutionally entrenched in Canada as part of the ***Constitution Act***, 1982, did not contemplate concerns over the environment. When the basic division of powers was set out in 1867 the framer of the BNA Act had not foreseen that environmental concerns would occupy a separate area of concern. As a consequence, in the resulting division of powers between the federal and provincial governments there is no direct head of power relating to the environment.

In general, the segregated powers attributed to the federal and provincial governments are different in both scope and nature. The provincial powers under the BNA are broader and more general in scope, whereas the federal powers tend to be narrow yet specific. Provincial powers as a general rule are broad although somewhat limited. this is illustrated through three heads of power, s.92(13), "Property and Civil Rights in the Province", s.92(16) "Generally All Matters of a Merely Local or Private Nature in the Province", and s.92(10) "Local Works and Undertakings". These broad powers have been used successfully in the past to support legislation regulating trade within the province, labour relations, public health and noise pollution and it is easy to see where the environment might be classified under any of these powers. There exists, however, several limitations to provincial jurisdiction. The first is that the provinces may not legislate with respect to matters assigned exclusively to the federal government by s.91. A second limitation arises where valid federal and provincial legislation overlap. In such a case the provincial legislation is inapplicable to the extent that it is in direct conflict with the federal legislation. As well, it appears that the provincial legislation may not usually be applied to the federal Crown.

The areas of jurisdiction arising with respect to the federal government tend to be narrow pillars of power, some of which cover areas that have an environmental element. For example, the federal government has power under s.91(10) to legislate with respect to navigation and fishing, it is empowered under s.91(12) to deal with sea coast and inland fisheries and the power over criminal law is reserved to the federal government. The ability to enact legislation aimed specifically at criminal matters, without infringing provincial jurisdiction is a powerful tool held by the federal government in relation to the environment. It can be exercised in numerous circumstance. Federal power over the environment is also enhanced due to limitations in the provincial power. The fact is that the broad general powers over property and civil rights in the province and all matters of a local or private matter in the province operate only in relation to matters within the province. Consequently inter-provincial and international matters fall within the exclusive jurisdiction of the federal government. As a result projects or actions that environmentally affect areas outside of one province fall to the federal government for regulation. In a time when pollution tends to cross such boundaries in the air or water this jurisdiction is of increasing influence.

This discussion indicates that there is as yet no clear demarcation between the environmental jurisdiction of the province and the environmental jurisdiction of the federal Crown. As environmental issues become more and more important the federal government and the provincial governments are feeling their way through the constitutional constraints toward the resolution of competing interests. Until a consistent body of law has been developed it appears that each instance of conflicting jurisdiction will be resolved on an individual basis. One recent legal decision involving a dispute concerning these competing jurisdictions suggest that the federal government has jurisdiction even where the event was local. The case concerns the jurisdiction to deal with unlawful dumping in the waters of Johnstone

Strait near Beaver Cove in the province of British Columbia. The Supreme Court of Canada was asked to determine whether or not the ***Ocean Dumping Control Act*** was beyond the power of the Parliament of Canada where it pertained to a local incident within the boundaries of a province. In a split decision of four to three the Supreme Court of Canada in the case of Regina v. Crown Zellerback Canada Ltd. held that the Act was validly enacted by the federal government and therefore the action against Crown Zellerback was sustained.

Until more of these matters are adjudicated and the powers of the federal and provincial governments over the environment is clarified we can expect to see increased action by federal and provincial governments to occupy the field of environmental legislation and therefore we are likely to see increased friction between the federal and provincial governments. Unfortunately, in the absence of a unified plan this increased competition is likely to result in duplicate legislation and confusion both on the part of industry and the public.

Environmental Impact Assessments

One example of increasing jurisdictional tension between the provincial and the federal government is in the area of Environmental Impact Assessments. The federal government pioneered impact assessment in Canada through its Environmental Assessment Review ("EARP") Process which was first introduced in 1974. The process is administered by the federal government through the Federal Environmental Assessment Review Office ("FEARO"). Since its introduction the process has gone through a number of modifications. In 1984 the policy was crystalized through an Order in Council known as the EARP Guidelines Order. This Order was intended to act as a guideline for the federal cabinet when dealing with projects or issues that had an environmental impact. It was to be discretionary, not binding, and its purpose was to allow for the evaluation of the effects of federal policies and projects on the environment.

Until 1989 the policy was administered in a discretionary manner, only being invoked with respect to policies and projects being implemented by federal departments. The discretionary nature of the guidelines was radically changed, however, in 1989 as a result of a decision of the Federal Court of Canada concerning the Rafferty-Alameda Dam projects in Saskatchewan. In the decision of Canadian Wildlife Federation Inc. v. Canada, handed down on April 10, 1989 by Mr. Justice

Cullen of the Federal Court, it was held that the EARP Guidelines were in fact binding legislation and not merely policy directions. Consequently, the court concluded before any decision to grant a federal approval could be made an assessment under the EARP Guidelines Order would have to be undertaken.

This represented a drastic change in the state of the law. In the Rafferty-Alameda case the Saskatchewan government had undertaken a water conservation and management program involving two dams. The principal areas of federal authority affected by the project included navigable waters, boundary waters, migratory birds and federal lands. As well, as the water in question eventually flowed into the United States and back into Canada and into Manitoba, the project had an international and interprovincial effect. The federal government had reviewed the project and had provided a list of concerns to the Saskatchewan government but, notwithstanding these concerns, had not acted to undertake an EARP assessment of the project before granting its approval.

Opponents to the project brought an action in court in order to force an environmental assessment by the federal government. The Federal Court trial division, in Justice Cullen's decision, and later the Federal Court of Appeal agreed with the contention of the opponents of the Dam project that an EARP assessment was mandatory.

As a result of this far reaching decision the requirement for an environmental assessment of federal projects, decisions, or programs that involve federal financial guarantees cannot be ignored. Parties who do not proceed to undertake an assessment pursuant to the Guidelines Order run the risk that any federal authority or permit required could be lost if the project is challenged on the basis of a failure to undertake an EARP assessment.

This substantial and far reaching change in the law was brought about not by the force of new legislation, but by the imaginative application of existing guidelines to an environmental concern. The results are far reaching in that any project requiring substantive federal government involvement may now be subject to an assessment which could involve a complete public hearing. Consequently, before any such project can proceed, an assessment in compliance with the Guidelines Order must be undertaken. For example, where a federal department is the sponsor of a project (eg. the Banff Highway Twinning), or where a federal department has decision-making authority over a project (granting a licence with respect to navigable waters, etc.), or where the project may affect an area of federal responsibility (Indians and Indian lands), or where the Government of Canada makes a financial commitment to a proposal (eg. loan guarantees - Oslo project, Lloydminster upgrader) or where the project is located on lands, including the offshore, that are administered by the federal government (Hibernia) these projects are likely to be subject to an EARP review.

The federal government has embraced the Court's decision and has embarked upon a revitalized program of Federal Impact Assessment. This action by the federal government has had an effect upon the response of the provinces with respect to Environmental Impact Assessments. Rather than being shut out of the process the provinces are recognizing the need to meet the federal assessment challenge head-on by either occupying the field themselves or by co-operating with the federal government in joint endeavours. In British Columbia the provincial government and federal government have just recently completed a joint Environmental Impact Assessment of the Celgar pulp facility in British Columbia. Other provinces are also acting to implement their own Environmental Impact Assessment legislation or are co-ordinating efforts with the federal government in order to be a part of the process. In Alberta, although the provincial government initially indicated that no assessment would be required with respect to the proposed Alberta Pacific Pulp Mill project it later changed its mind. After it was disclosed that the federal government might assess the proposal under the EARP Guidelines the provincial government re-assessed its initial determination and joined with the federal government in a joint hearing to assess the project.

The Alberta government is also acting to better define its jurisdiction with respect to impact assessment. The provincial government has included in Division 1 of the proposed Alberta Environmental Protection and Enhancement Act a complete section dealing with Environmental Impact Assessments. The proposed legislation is similar to the federal legislation in that it is intended to operate as a planning tool in order to assess a project (or indeed any "activity") before a decision to permit the project is made by the provincial authority. Under s.44 of the proposed Act the purposes of an environmental impact are stipulated to:

- achieve the goal of environmentally sustainable development;
- integrate environmental protection into economic decisions at the first possible stage in planning a project;
- determine the environmental consequences of a project before a decision to proceed is made; and
- provide for the involvement of the public and departments of the government and government agencies in the Environmental Impact Assessment Process.

As a consequence, any project proponent is well advised to factor into its planning and development process not only involvement and interaction with possibly both levels of government, but also a requirement to co-ordinate and complete an Environmental Impact Assessment involving, in many cases, the general public.

The federal government is well involved in re-assessing and modernizing the EARP assessment process. Bill C-78, which was introduced into parliament during its last sitting, is the federal government's response to long standing public calls for an improved Federal environmental assessment process and their response to the court decisions which have interpreted the existing EARP Guidelines Order as mandatory legislation. Some of the changes proposed under the ***Canadian Environmental Assessment Act*** include the following:

- the Act gives the Environment Minister, and not the minister of the initiating department, the authority to order public reviews or to permit mediation (s.16 - Screening, s.17 - Mandatory Study, s.21 - Referral to Minister, s.24 - Referral by Minister);

- the Act provides for mediation as an additional public accommodation technique (s.25 - Mediation and Review Panels);

- through the use of regulations, which have yet to be promulgated, the Act may ensure that an increased number of government activities are subject to the environmental assessment process;

- the new Act provides for co-operation with provinces and for the appointment of joint review panels between the federal authority and the government of a province or their delegates (s.37 - Joint Review Panels, s.43 - Transborder and Related Environmental Effects);

- the new Act deals specifically with transborder assessments for environmental effects (s.43 - Inter-provincial Environmental Effects and s.44 - International Environmental Effects);

- the Act establishes the Federal Environmental Assessment Agency and grants power to summon witnesses and compel the production of documents;

- the new Act not only requires completion of assessments before the final decision is made but also requires preparation and implementation of follow-up measures and mitigation measures (s.35 - Design and Implementation of Follow-Up Program); and,

- the new Act specifically deals with the assessment of foreign aid projects (see s.55).

It is clear that Environmental Impact Assessment will play an important role in the launch of any project or proposal that has the affect to environment. Undoubtedly longer lead times and closer co-operation both with the public and the government will be required in order to carefully steward a project from its genesis to its operation.

Common Legislative Changes

As alluded to earlier both the federal and provincial governments have over the last five years instituted substantial legislation affecting the environment. The first major piece of legislation affecting the environment was the ***Canadian Environmental Protection Act***. That was followed by the Ontario ***Environmental Protection Act***, amendments to the B.C. ***Waste Management Act*** and in Alberta, to the proposal last spring to implement a new ***Environmental Protection and Enhancement Act***. All of these new initiatives enjoy the virtue of being substantially backed by public opinion. Environmentally pro-active legislation is high on the government's agenda. Most of this legislation has a number of common elements including increased enforcement powers, higher fines, direct liability for officers, directors and employees and increased penalties for environmental offences. Although a revamping of environmental legislation was overdue it is unfortunate that many of these new Acts do not seriously deal with alternative methods to fines for ensuring compliance with laws or seek to encourage alternate dispute resolution through mediation of environmental concerns for example. Alternatives to traditional sanctions are crucial but lacking in the new legislation. Recognition of the changing public and governmental interest in environmental matters and a lack of alternate resolution methods contained in the new legislation should encourage industry to re-assess its position and prepare itself to comply with reasonable environmental standards, and where necessary, to defend itself against inappropriate charges.

Some of the more common elements of the new Acts are discussed below.

Officer and Director Liability

In the past if a Company was charged with an environmental offence more often than not a fine was paid, however, no person was held individually liable or went to jail. Increasingly environmental legislation contains specific provisions that allow the courts to pierce the corporate veil in order to assess liability against officers, directors, and in some instances employees. Under the ***Canadian Environmental Protection Act*** s.122 makes officers and directors expressly liable. Under the Ontario ***Environmental Protection Act*** s.147 places a duty on officers and directors to ensure compliance with the law - failure to ensure compliance could result in a charge against the officers or directors. In Alberta the proposed ***Environmental Protection and Enhancement Act***, through s.202, imposes a similar duty and provides for a maximum $1 million fine for failure to fulfill the imposed duty.

All of these provisions are of recent vintage, however, it is clear that the courts are prepared to deal with the responsibility of the individual in relation to a corporate breach of environmental standards. Prior to the enactment of express provisions holding officers and directors personally liable the courts were required to rely upon their inherent contempt powers in order to hold an individual responsible for an environmental offence by a company. In pioneering cases such as the *Best Plating* case the president of a company which had been convicted of numerous repeat violations of pollution standards resulting from the disposal of electroplating wastes was sentenced to six months in jail for contempt. Although a milestone sentence, it was overturned on appeal.

Recently, however, empowered by express provisions in the legislation and strengthened by public concern the courts have been more successful in charging directors and officers directly for corporate offences. In the decision in *Regina* v. *Blackbird Holdings Ltd.* handed down in Picton, Ontario on June 22, 1990 the president of the defendant company was sentenced to six months in jail for his part in the improper disposal of 185, 45-gal. drums containing various contaminants on land owned by Blackbird Holdings Ltd.

The buried barrels leaked and introduced trichloroethylene, a known carcinogen, into the ground and groundwater. Neighbours complained with respect to the quality of their well water and the Ontario Ministry of Environment conducted a survey which led them to excavate the buried drums. The evidence disclosed that the president of Blackbird Holdings Ltd. had knowledge of the improper disposal and burial of the drums and found him guilty along with the company. The court had little sympathy for the officer stating:

> "This [the damage] has been caused in my opinion by one person who was the power behind the two corporations that we are dealing with here, Burprom Construction and Blackbird Holdings".

This case indicates that the courts are now empowered and are willing to approach the sentencing of officers for the offences committed either by corporations or with the compliance of a corporation. Compelling evidence of involvement will still be required, however, it is clear that as more and more statutes expressly provide for direct liability for officers and directors, and as the case law develops to provide precedents for the sentencing of these parties, we can expect to see increased use of this remedy against corporate officers and directors. Indeed, many observers are carefully watching a case which is slowly moving through the court system involving a charge against T. Bata, the president of the Bata Shoe Corporation, for violations alleged to have resulted from action by the Bata Shoe Corporation contrary to the provisions of the Ontario ***Water Resources Act***. This is the first example of an officer of what may be termed a major multi-national corporation being charged for a corporate violation of an environmental statute.

Consequences of a Failure to Comply

The consequences arising from a failure to meet enhanced environmental standards can be harsh under the terms of new legislation. Part VII of CEPA sets out numerous offences and punishments which include substantial fines for a variety of offences which range from a $300,000 maximum fine for a summary conviction offence to the possibility of a fine of $1 million for an indictable offence. As well, the possibility of imprisonment is available in relation to an increasing number of environmental offences. Indeed, CEPA creates a new crime relating to "damage to the environment" which can provide for imprisonment for up to five years.

Controversial area relates to the imposition of a bounty system for environmental offences similar to one now in place with respect to ***Fisheries Act***. The proposed Fines and Execution of Orders Proceeds Regulation released on June 16, 1989 recommended the payment of proceeds of any fines imposed under CEPA to the prosecutor and the informant. This form of incentive seems misplaced when one considers that public funds will no doubt be required to clean up environmental problems in the future and that these fines could be best used to finance clean-up.

A similar harsh message has been conveyed by the provinces. In the Ontario ***Environmental Protection Act***, and in the proposed Alberta ***Environmental Enhancement and Protection Act***, new increased fines are authorized. Sections 146 and 147 of the Ontario Act provide for a hierarchy of fines which extend from $50,000 for the first conviction up to a maximum fine of $2 million. Under the proposed Alberta Act the maximum fine pursuant to s.199 would be $1 million or imprisonment for not more than six months or to both a fine and imprisonment.

It should be noted that these rising penalties must be viewed against a background of heightened enforcement and, in the case of CEPA, the ability of the public itself to require the government to investigate and act upon reported environmental offences (CEPA s.108, Investigation of Offences). As well, each of the new legislative initiatives views continuing pollution offences as separate acts. In the case of the proposed Alberta legislation, where an offence is committed or continued on more than one day, the party can be liable and can be convicted for separate offences for each day on which the offence is committed or continued. Accordingly, there is liability for a maximum fine of $1 million for each day that the offence continues.

The courts are prepared to utilize these high fine levels. Last December in B.C. Cariboo Pulp and Paper was fined $275,000.00 in connection with two separate infractions. The first related to a turpentine and sulfur gas leak which attracted a fine of $25,000.00 and the second related to a release of 80,000 litres of "caustic white liquor" which passed through the mills waste treatment plant and eventually entered the Fraser River. That charge attracted a fine of $250,000.00. Also in B.C. Aspen Planers ltd. was fined $27,000.00 for a drip tank leak from their sawmill operation at Merritt, B.C.

Profit Stripping

New legislation has adopted as part of its philosophical makeup a requirement that no party should benefit from pollution. Profit stripping provisions which allow a court to assess and fine companies for an amount equal to any benefit that accrued due to pollution was first seen in Canada as a part of CEPA. Section 129 of CEPA empowers a court to order the convicted offender to pay an amount equal to any monetary benefits resulted from the commission of the offence. Similarly, in the proposed Alberta ***Environmental Protection and Enhancement Act***, s.200 provides a similar remedy indicating that "...in addition to a fine under s.199, a fine in an amount equal to the court's estimation of the amount of those monetary benefits" can be assessed where the court is satisfied that a benefit arose as a result of the commission of the offence.

Increased Enforcement

Concurrent with the increase in penalties both federal and provincial agencies are placing increased emphasis on enforcement. There have been in Alberta a noted increase in the use of control orders, stop orders, tickets and fines. Control orders rose from seven in 1987 to twenty-six in 1990. Currently, Alberta Environment has indicated that it is adopting a policy of enforcement distinct from a former position which allowed to some extent for negotiated compliance. The enforcement division of Alberta Environment is completing its new enforcement policy which will reflect the mandate of the division "to achieve the protection, enhancement and wise use of the environment, now and in the future, by providing firm but fair enforcement of environmental legislation in a timely and consistent manner".

The policy reflects the department's move away from negotiation at the enforcement stage by confining negotiation to the licensing of operations. The Department has indicated that once operating conditions have been agreed to and incorporated into a licence, they will be strictly enforced. The implementation of this policy is seen by the department as one method of ensuring that parties who comply with the law will not be put at an unfair disadvantage by those who ignore the law.

Increased Search Powers

All of the new environmental legislation contains increased powers to conduct searches in order to secure evidence of an environmental offence. Government investigators may enter and inspect any place to determine whether an offence has been committed. Additional search powers, including the seizure of documents and the detention of any relevant information can be accommodated through express powers contained in these Acts which authorize removal and seizure. Although all of the Acts contain provisions which permit "warrantless searches" this matter is currently subject to review as a result of a decision by the Supreme Court of Canada which requires an objective adjudicator to assess the reasonableness of such a search.

Private Prosecutions

As well as increasing penalties through regulation the new Acts often also provide for an express civil remedy against a polluter by affected individuals. For example, s.136 of CEPA provides that any person who suffers loss or damage as a result of conduct that is contrary to any provision of that Act or its regulations may sue to recover from the responsible person the amount lost. This creates a new civil cause of action which is linked to the Act and its regulations.

In addition, individuals are utilizing traditional civil remedies such as nuisance, riparian rights, strict liability, negligence, trespass and deceit in order to prevent potentially harmful environmental actions from occurring or to recover for loss that they have suffered due to an environmental problem created or enhanced by another individual. The Globe and Mail on Tuesday, May 7, 1991 carried the story of a crab fisherman who is suing two pulp mills in Howe Sound for destroying his livelihood by dumping wastes into his fishing grounds in Howe Sound. It is clear that environmental causes of action, with or without express assistance through new legislation, are likely to increase as people seek to enforce their desire for a clean environment.

Duty to Report

New legislation in Ontario, British Columbia and Alberta requires parties to report any environmental offences. The proposed provision contained in the Alberta ***Environmental Protection and Enhancement Act*** requires a person having control of a hazardous substance to report a release of that substance to the government, to the owner of the substance and to any other person who might be directly affected by the release. Coupled with this duty to report there is also a duty to take remedial measures to repair, remedy or confine the effects of the release.

Meeting the Challenge of New Changes

The best and most logical advice to give when confronted with the changing provisions of environmental legislation is to ensure that you are knowledgeable about the environmental laws and regulations that affect your industry. The next best, and obvious advice is to ensure that you comply with those provisions. Parties should be aware of the consequences that arise both personally and to the corporation as a result of the failure to meet new and increasing environmental standards. Training should be implemented not only to make parties aware of the appropriate legislation but also to ensure that they can meet the standard necessary to counter-act any environmental problem and to mitigate its effect. Employees should be trained with respect to dealing with investigations and they should understand both their personal legal rights and the company's legal rights. They should feel comfortable with respect to their obligation to report environmental offences and their participation in an investigation should one be required.

Continued education, training and co-operation will be necessary to ensure that industry, the government and the public can adapt and operate in light of increasing environmental concern and enforcement.

Attached to this paper is a listing and comparison of environmental legislation in Canada.

SUMMARY OF CANADIAN ENVIRONMENTAL LEGISLATION AND PENALTIES

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
FEDERAL				
Arctic Waters Pollution Prevention Act R.S.C. 1985, c.A-12 For environmental issues north of the 60° in Arctic waters. (Current to 90.08.21)	**s.4** - No person or ship shall deposit or permit the deposit of waste of any type where waste enters the Arctic waters **s.5** - Duty to report deposit of waste or danger thereof **s.5(2)** - Master of ship has duty to report any accident to prescribed pollution prevention officer **s.8** - Governor-In-Council may require evidence of financial responsibility or an indemnity bond ss.16, 17 - Duty to assist and not obstruct pollution control officers	**s.18** - Contravention of s.4 - fine for person, up to $5,000; for a ship up to $100,000/day of offence **s.19** - Additional offences for a person, up to $25,000; for a ship up to $25,000	**s.6** - Civil liability of: a) any person exploring or developing natural resources on adjacent land b) any person carrying on any undertaking on mainland or islands of Arctic c) owner of ship navigating within the Arctic waters or owners of the cargo are respectively liable and in the case of a ship owner are jointly and severally liable (in the case of an oil and gas operation, up to $40MM) **s.20** - Sufficient proof of the offence to establish it was committed by an employee or agent, unless accused establishes that all due diligence was exercised	**s.15** - Pollution prevention officers may enter, examine, take samples, require production of any relevant documents at any reasonable time **s.15(4)** - Re: ships, may board, order out of the zone, or order any ship to take part in the cleanup **s.23** - Right to seize ship and cargo

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
FEDERAL				
(Proposed) *Arctic Shipping Pollution Prevention Regulations*				
Draft regs. published in Canada Gazette, Pt.I July 7, 1990, p.2526.	Regulations control the dates when ships enter into shipping Safety Control Zones in the Arctic Waters. All ships carrying more than 453 m^3 of oil are separated into classes and are subject to the regulations.			

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
FEDERAL				
Canada-Newfoundland Atlantic Accord Implementation Act S.C. 1987, c.3 Newfoundland offshore. (Current to 90.08.21)	**s.161(1)** - No person shall cause or permit a spill on or from any portion of the offshore **s.161(2)** - Duty to report spills **s.161(3)** - Duty to take reasonable measures to repair or remedy the condition resulting from the spill **s.194** - Offence to falsify or knowingly destroy documents and records re spills.	**s.162** - Recovery of loss, damages, costs or expenses from person who obtained an authorization in respect of the work or activity. Limits of liability defined by ***Canada-Newfoundland Oil and Gas Spills and Debris Liability Regulations***, SOR/88-262; up to $40MM less the costs of clean-up **s.194 - 195** - Contravention of s.161 a) on summary conviction, fine up to $100MM or prison up to 1 year or both/day of offence b) on indictment, fine up to $1MM or prison up to 5 years or both/day of offence.	**s.162(b)** - All persons whose fault or negligence the spill is attributable or who by law are responsible for others to whose fault the spill is attributable are jointly and severally liable to the extent determined for all actual loss or damage incurred **s.198** - "In any prosecution for an offence ... it is sufficient proof to establish it was committed by an employee or agent of the accused ... unless the accused establishes that the offence was committed without the knowledge or consent of the accused or that the accused exercised all due diligence to prevent the commission of such offence."	**s.165(2)** - Person conducting an inquiry into a spill "has and may exercise all the powers of a person appointed under P & I of ***Inquiries Act***."

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
FEDERAL				
Canada Shipping Act				
R.S.C. 1985, c.S-9 (Note: s.655(2) excludes application of the pollution presentation and central provisions (Part XV) in relation to a discharge or spill from a ship engaged in exploration or production of oil and gas in the offshore controlled by the Federal Government). (Current to 90.08.21)	Regulations prohibiting pollution including: ***Air Pollution Regulations***, C.R.C., vol. XV, c.1404 ***Garbage Pollution Prevention Regulations***, C.R.C., vol. XV, c.1424 ***Maritime Pollution Claims Fund Regulations***, C.R.C., vol. XVI, c.1444, as amended by SOR/90-82 ***Fisherman's Notice of Claim for Loss of Income***, C.R.C. vol. XV, c.1423, as amended. ***Oil Pollution Prevention Regulations***, C.R.C. 1978, c.1454, as amended.	**s.664** - Any person or ship that discharges a pollutant in contravention of any regulation is liable on summary conviction to a fine not exceeding $250,000 **s.666** - It is an offence to disobey a pollution prevention officer. Fine: not exceeding $200,000. Refusing to assist a pollution prevention officer. Fine: not exceeding $10,000.	**s.677** - Owner of a ship is liable for oil pollution damage from the ship and for costs and expenses incurred to prevent pollution (see s.674(2) for oil and gas explanation exemption)	**s.662** - Powers of pollution prevention officer include right to board and inspect ship, take samples and direct the ship. **s.672** - Right to detain ship where an officer believes on reasonable grounds that an offence has been committed.
	Ship-Source Oil Pollution Fund Regulations, SOR/90-82			

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
FEDERAL				
(Proposed) ***Canadian Environmental Assessment Act*** Bill C-78				
Anticipated to be implemented in 1990. The purpose of this Act is to provide a legislative structure and refine the Federal EARP process. The Act will ensure that before a department or agency of the Government of Canada decides to carry out a project an environmental assessment is undertaken. The steps contemplated include screening, mandatory study, mediation and public review. **Competitive Crown corporations set out in s.85 of the *Financial Administration Act* or Schedule III of that Act, such as Petro-Canada, are not subject to the established process, but may be subject to an amended process pursuant to regulations yet to be promulgated (s.55(j))** **(1st reading 90.06.18)** **(2nd reading 90.06.26)**	**- Duty upon a "federal authority" to conduct an environmental assessment of any project.** **- A modified assessment process to be prescribed by regulation may apply to Petro-Canada due to status as a Crown corporation but will not ordinarily apply to private corporations unless the project receives financial assistance from the federal government or is undertaken on federal lands or requires the approval of a federal agency.** **- Will affect domestic and international operations.** **- Will add another level of environmental review by the Federal Government in addition to Provincial requirements.** **- Increased opportunity for public hearings and associated delay.**	**- All projects must be screened by Assessment Agency before they are undertaken.** **- Projects will be screened and may be referred to mandatory study, mediation or public hearing where there may be a "significant" environmental effect or where public concerns may warrant (s.16).** **- Prohibition power by the Minister to prevent any party from proceeding with a project until a public review is complete.**	N/A	**Ability to subpoena witnesses for reviews (s.32).**

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
FEDERAL				
Canadian Environmental Protection Act S.C. 1988, c.22 Purpose: General (Current to 90.08.21)	**s.s. 111-126** - Failure to give information - not exceeding $200,000 or imprisonment for 6 mos. or both. Fraud, misleading info: summary conviction $300,000, 6 mos. or both; Indictment: up to $1MM, 5 years or both. Damage to environment: fine or prison up to 5 years	(See Offences)	**s.122** - Any officer, director or agent who "directed, authorized assented to, acquiesced in, or participated in the commission of an offence".	**ss.101-104** - Authorization to issue warrants, search includes any internal computer system and powers of seizure.

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
FEDERAL				
Environmental Assessment Review Process Order (EARP) SOR/84-467 (Current to 90.08.21) Applies to any proposal that prior to the coming into force of the ***Canadian Environmental Assessment Act*** was referred to the Minister for public review and for which an Environmental Assessment Panel was established (s.69 - ***Canadian Environmental Assessment Act***).	Duty to carry out an environmental assessment of a proposal to determine whether there will be any adverse environmental effects. Currently applied by Federal departments, agencies and some Crown corporations where they are the proponent of a project, where they have a decision-making authority over the project, where a project may have an environmental effect on an area of Federal responsibility, where the Government of Canada makes a financial commitment or where its proposal is located on lands, including the offshore, that are administered by the Federal Government.	Subject to injunctive relief requiring the completion of an assessment and, where the effects are not "insignificant" a public review. (See Canadian Wildlife Federation Inc. v. Canada Minister of Environment)	N/A	N/A

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
FEDERAL				
Fisheries Act				
R.S.C. 1985, c.F-14, as amended. Purpose: Protection of fish and fish habitat. (Current to 90.08.21) Amendments to offences, penalties and search & seizure sections by Bill C-74, still at 1st reading August '90.	**s.35** - No harm to fish habitat. **s.36(3)** - No deposit of deleterious substance. **s.38** - Duty to report, take all reasonable measures, to assist inspectors. **s.62** - No obstruction of fishery officers (Bill C-74) **s.63** - No making false or misleading statements (Bill C-74)	**s.40** - (Bill C-74) Contravention of ss.35, 36(1) or (3); up to $300,000/day or prison up to 6 mos. or both. For indictable offence: fine up to $1MM/day, or prison up to 3 years or both. Contravention of s.39 - fine up to $200,000 or prison up to 6 mos. or both **s.78** - (Bill C-74) Any other contravention of Act or reg.; fine up to $100,000/day or prison up to 1 year or both.	**s.38(4)** - "Any person who owns the deleterious substance, or has the charge, management, and control thereof or causes or contributes to causation of danger" - must report - duty to take all necessary action **s.78.2** (Bill C-74) Any officer, director or agent of the corporation who directed, authorized, assented to, acquiesced in or participated in the commission of the offence is a party to and guilty of the offence, and is liable ... whether or not the corporation has been prosecuted. **s.78.3** - (Bill C-74) Sufficient proof of the offence to establish it was committed by an employee or agent unless accused establishes offence was committed without his knowledge or consent. **s.78.6** - Due Diligence defence.	**s.49** - (Bill C-74) To ensure compliance, a fishery officer may enter, inspect any premises, vessel or vehicle, may open any container, examine, conduct tests, require production of any documents. **s.51** - (Bill C-74) Power to seize.

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
FEDERAL				
(Proposed) ***Hazardous Waste Management Regulation for Federal Institutions*** Presently being drafted by the Waste Management Branch, Conservation and Protection, Environment Canada, under the provisions of the ***Canadian Environmental Protection Act*** (CEPA). Purpose: To provide uniform Waste Management standards for all Federal departments, agencies and Crown corporations. (Discussion is on-going with the Federal Government with respect to application of Regulations). (Current to 90.08.21)	- Requires Petro-Canada and subsidiaries, due to its Crown corporate status, to meet new stringent Federal Waste guidelines in addition to provincial requirements. - Does not ordinarily apply to other oil and gas companies. - Petro-Canada must meet very stringent Waste Management requirements. - Preliminary cost estimates by Petro-Canada indicate capital costs of approx. $100MM - $150MM for company's refining and marketing sector, $25MM in additional annual operating costs at production facilities and $180MM additional annual expense for drilling operations. - Prohibition against disposal of waste except in accordance with these Regulations.			

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
FEDERAL				
Northern Inland Waters Act				
R.S.C. 1985, c.N-25 as amended. Rivers, basins and tributaries in N.W.T. and Yukon. Waste in water management areas. (Current to 90.08.21)	**s.4.(2)** - No altering, diverting, storage, or use of water without a licence. **s.7** - No person shall deposit or permit the deposit of waste of any type. **s.9** - Duty to assist inspectors. **s.34** - No obstruction of inspectors or making false statements. **s.39** - 2 year limitation period.	**s.35** - Contravention of s.4(2) or s.7, or unauthorized water use, fine up to $5,000/day of offence.	**s.38** - "It is sufficient proof of the offence to establish that it was committed by an employee or agent of the accused whether or not the employee or agent has been identified or has been prosecuted" ... unless done without his consent or he exercised all due diligence.	**s.33** - Right to enter, conduct inspections, examine documents, except into a private dwelling which necessitates search warrant.

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
FEDERAL ***Oil and Gas Production and Conservation Act*** R.S.C. 1985, c.0-7, as amended. Act applies to the exploration and drilling for and the production, conservation, processing and transportation of oil and gas in the Yukon, NWT and offshore (but not Arctic waters). (Current to 90.08.21)	**s.18** - Waste prohibited **s.24** - No unauthorized discharge, emission or escape of oil or gas **s.25** - No person shall cause or permit a spill **s.25(2)** - Duty to report **s.25(3)** - Duty to take reasonable measures	Loss, damage, costs or expenses re: environmental incidents recoverable.	Limits of liability established by ***Oil and Gas Spills and Debris Liability Regulation*** SOR/87-331: up to $40MM minus the cost of clean-up **s.25(9)** - No person is personally liable unless it is shown he did not act reasonably **s.26** - Recovery of loss, damage, costs or expenses from the person who obtained an authorization for the work or activity, without proof of fault or negligence **s.27** - Minister shall require person who obtains work authorization to provide for financial responsibility re: payment of claims in form of letter of credit, guarantee, or indemnity bond.	**s.28(1)** - When an environmental incident occurs, Minister may direct that an inquiry be made subject to the ***Canadian Transportation Accident Investigation and Safety Board Act.*** **ss.4 - 21** - Powers under this Act to enter search and seizure. If done without consent of person in charge, must be done with a search warrant.

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
FEDERAL				
Pest Control Products				
R.S.C. 1985, c.P-9, as amended. Purpose: Control toxic substances. (Current to 90.08.21)	**s.4** - No manufacturing under unsafe conditions. No deceptive packaging or labelling. No selling or importing of unprescribed products. No exporting or inter-provincial movement of unprescribed products. **s.9** - No obstruction of inspectors.	**s.11** - Indictable - prison to 2 years or on summary conviction.	**s.11(2)** - Offence by agent or employee.' Accused must establish that offence was without his knowledge or consent, and that he exercised all due diligence.	**s.7-10** - Powers of inspectors to seize and detain controlled product.

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
FEDERAL				
Territorial Lands Act				
R.S.C. 1985, c.T-7 Territorial lands are lands in the Yukon or N.W.T. that are vested in the Crown or of which the Government of Canada has power to dispose.	Duties re permits under ***Territorial Land Use Regulations***, C.R.C., c-1524. **s.20** of Regulations - where an emergency, duty to report "immediately thereafter" describing the duration, nature and extent of the operation. **s.38** of Regulations - Duty to assist Inspector. **s.40** of Regulations - No making false statements.	**s.7** - Contravention of regulations, or terms and conditions of permits granted, fine not exceeding $5,000. **s.41** of Regulations - Land use operation may be shut down by inspector, if contravention of terms of the permit.	"Permittee".	Under the ***Territorial Land Use Regulations***, **s.38** - Permittee must permit an inspector at any reasonable time, to enter, make inspections.

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
FEDERAL				
Transportation of Dangerous Goods Act				
R.S.C. 1985, c.T-19 Purpose: Regulate transportation of dangerous goods. (Current to 90.08.21) In the Dangerous Goods Newsletter, v.10, no.1 (Spring 1990), Transport Canada outlined 37 possible amendments including: - more careful definition of Federal jurisdiction and applicability - increased fines and jail terms - ensuring both a company and its officers can be found liable - increased powers of inspectors. Amendments to be introduced Fall/Winter 1990.	Defined by schedule Transportation of dangerous goods between municipalities.	**ss.4-8** - Summary conviction - up to $50,000/1st offence, $10,000/subsequent. Indictment: 2 years.	**s.10** - It is sufficient proof of the offence to establish that it was committed by an employee or agent, whether or not he has been identified or prosecuted, unless accused establishes he took all reasonable measures to prevent its commission. **S.11** - Any officer, director, or agent that "directed, authorized, assented to, acquiesced in or participated in".	**s.14** - Powers of inspectors. Entry and inspection where reasonable grounds exist; may take samples and examine documents.

SUMMARY OF CANADIAN ENVIRONMENTAL LEGISLATION AND PENALTIES

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
ALBERTA				
Clean Air Act (To be repealed by new Act)				
R.S.A., 1980 c.C-12, as amended. Purpose: To control air pollution. Air pollution defined as presence of air contaminant in excess of prescribed concentration. (Current to 90.08.21)	Permits required for emissions. **s.3** - No construction of manufacturing or processing plants for specified goods without permit. **s.4** - No operation of plant without licence. **s.5** - No changes to plant without permit. **s.6** - No disposition of permit. **s.8** - Renewal of permit. **s.13** - Failure to comply with emission control order.	**s.3(10)** - Failure to comply with notice, $5,000 each day. **s.14** - Failure to comply with stop order: up to $10,000 per day or prison up to 12 mos. or both. **s.15** - Failure to comply with direction: up to $5,000 per day. **s.16** - Other: Fine not exceeding $25,000 and default, to a term of imprisonment not exceeding 3 months. **s.17** - 2 year limitation.	**s.15** - Power to enter, investigate, inspect, make copies of records, carry any powers conferred by Director of Pollution Control or Director of Standards and Approvals.	**s.15(1)** - Entry and inspection power.

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
ALBERTA				
Clean Air (General) Regulations (To be repealed by new Act)				
Alta. Reg. 216/75, as amended. (Current to 90.08.21)	**ss.3-4** - Application for permit to construct a plant. **ss.7-12** - Licence to operate plant. **ss.13-17** - Amendment to permit. **ss.18-20** - Amendment to Licence. **ss.21-24** - New Licence.	**s.10** - Summary conviction offence, $1,000 fine for each day offence continues. **s.13** - Returns and reports - $1,000/day offence continues.		

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTOR /EMPLOYEE LIABILITY	SEARCH POWER
ALBERTA				
Clean Water Act (To be repealed by new Act)				
R.S.A. 1980, c.C-13 Purpose: To provide a mechanism to ensure quality of water is not impaired. (Current to 90.08.21)	**s.3** - No projects; petroleum products or related plants; or metal, wood or chemical plants without permit for construction. **s.4** - Licence for operation of facility. **s.17** - Shall not deposit or permit the deposit of a water contaminant if likely to degrade the chemical or biological quality of water. **s.20** - 2 year limitation.	**s.14** - Control Order - may be ordered to install, replace or alter any equipment designed to control or eliminate discharge. **s.15** - Stop Order - Minister may order permanent or temporary shutdown of any operation causing contamination. Failure to comply - $50,000/day or imprisonment of one year. **s.16(4)** - Failure to provide information - $5,000/day contravention continues. **s.19** - General Penalty - $25,000, and in default, prison up to 3 months.	Person to whom stop and control orders are directed. **s.16(3)** - Owner or operator of facility or plant must provide information.	**s.16** - Power of entry and inspection.

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
ALBERTA				
Clean Water (General) Regulations				
Alta. Reg. 35/73 as amended. (Current to 90.08.21)	**s.9** - Reporting requirement. **s.11** - No discharge of contaminant without permission. **s.13** - Application for licence for existing water facility	**s.4, 5(2), 10, 11(2)** - Failure to comply with orders, reporting requirements; Penalty for discharge - $1,000/day offence continues. **s.12** - Recovery of cost of remedial work by Crown.	Owner, operator or person in charge of facility.	
Clean Water (Industrial Plants) Regulations				
Alta. Reg. 36/73 **ss.4-7** - Application for permit to construct industrial plant. **ss.8-13** - Licence to operate industrial plant. **ss.14-17** - Amendment to permit. **ss.19-21** - Amendment to licence. **ss.22-25** - New licence. (Current to 90.08.21)				

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
ALBERTA				
Clean Water (Municipal Plants) Regulations Alta. Reg. 37/73 **s.1(b)** - Municipal plant excludes industrial facility. **ss.4-6** - Application for permit to construct municipal plant. **ss.7-11** - Licence to operate municipal plant. **ss.12-15** - Amendment to permit. **ss.18-20** - Application for new licence. **ss.21-29** - Samples and disinfection of water. (Current to 90.08.21)				

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
ALBERTA				
Department of Environment Act				
R.S.A. 1980 c.D-19, as amended Purpose: Coordination of policies re: environment - stop orders under Clean Water and Clean Air exempted from provisions of this Act [s.17(13)] (Current to 90.08.21)				

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
ALBERTA ***Environmental Protection and Enhancement Act*** **(*Proposed - for public discussion*)** Discussion draft released 90.06.18 for public discussion. Provincial panel to hold hearings throughout the province this fall. The purpose of the legislation is to provide one comprehensive environmental statute to deal with environmental matters. The legislation would replace the ***Agriculture Chemicals Act***, the ***Beverage Container Act***, the ***Clean Water Act***, the ***Clean Air Act***, the ***Groundwater Development Act*** and the ***Land Surface Conservation and Reclamation Act***. Highlights include: - establishment of a legislated Environmental Impact Assessment Process (EIA); - increased public consultation and participation in licencing and permitting activities;	**s.1(dd)** - Duty to deal with hazardous substance accrues to "person responsible" which by definition includes owner, successor, assignee, executor, or administrator of owner, every person who has or has had charge, management or control of substance or of handling, storage, use, disposal, transportation or display of the substance. **s.25** - Environmental Protection Orders may be issued to prohibit or require various action. **s.55** - General prohibition against carrying out an act without appropriate approval. **s.73** - Financial security may be required as surety for approvals.	**s.162** - Cost of emergency measures to control a release of a hazardous substance are to be paid by the person responsible. **s.198** - Offence provisions. **s.199(1)** - Penalties of up to $1,000,000 and six months imprisonment for providing false information, contravening an approval, contravening an enforcement order, not having an approval, etc. **s.199(2)** - Penalties of up to $500,000 or six months imprisonment for lesser offences. **s.200** - Profit stripping **s.201** - Separate offence for each day. **s.206** - Statutory recognition of due diligence defence.	**s.202** - Duty of officers and directors to take all reasonable care to prevent the commission of an offence. Penalty for breach of the duty is $1,000,000 or six months in jail.	**s.36** - Powers of inspector almost identical to the powers of an investigator. **s.144** - Power to collect data, samples and conduct investigations respecting a substance. **s.166** - Any two residents over 18 years of age can apply for an investigation of an alleged offence. **s.168** - Power to enter and search. **s.168(3)** - Power to copy or remove documents. **s.168(4)** - Right to legal counsel during questioning. **s.169** - Power to enter and search private dwelling house with consent, pursuant to judge's order or with a search warrant. **s.172** - Order to enter and inspect. **s.174** - Seizure without order or warrant. **s.175** - Search and seizure without a warrant.

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
ALBERTA				
Environmental Protection and Enhancement Act - Cont'd.				
- increased penalty provisions - fines up to $1,000,000 and jail terms of six months; - increased public access to information; - statutory requirements for waste reduction and re-cycling; - mandatory spill reporting and clean-up; - 25-year owner/operator liability for site clean-up and reclamation costs. - liability of corporate officers and directors for environmental offences.	**s.76** - Prohibition against release or permitting release of contaminants. **s.77** - Power to issue a pre-emptive environmental protection order. **s.82** - Financial security may be required by regulation for conservation and reclamation purposes. **s.83** - Duty to reclaim lands. **s.125** - Prohibition against handling hazardous waste without Personal Identification Number (P.I.N.). **s.127** - Manifest required to consign, transport or accept, store, treat, or dispose hazardous waste. **s.139** - Storage requirements for hazardous substances and pesticides generally. **s.141** - Prohibition against sale of contaminated material.			

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
ALBERTA *Environmental Protection and Enhancement Act* - Cont'd.	**s.146** - Duty to report that a substance is a hazardous substance (similar to D.S.L. requirement). **s.155** - Person having control of a hazardous substance, pesticide or contaminant that is released into the environment shall "as soon as he knows or ought to know of the release" report it. **s.157** - Duty to take remedial action to repair, remedy and confine the effects of a release. **s.184** - Enforcement Orders. **s.192** - Injunctive Relief. **s.197** - Private prosecutions. **s.202** - Duty of officers and directors.			

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
ALBERTA				
Hazardous Chemicals Act (To be repealed by new Act)				
R.S.A. 1980, c.H-3 Purpose: To promote public safety in the storage, handling, transportation and disposal of hazardous chemicals. **s.1(f)** - Hazardous chemical is a substance which may constitute a danger to the environment, plant or animal life or human health. **s.2** - Act binds the Crown. (Current to 90.08.21)	**s.7.1** - In the event of spill, shall take all reasonable emergency measures to repair, remedy and confine the effects of and remove the hazardous chemicals. **s.7.2** - Shall not generate hazardous waste and permit it to leave the premises unless allocated a personal identification number. **s.7.3** - Shall not consign, transport or accept for transportation, storage, treatment or disposal any hazardous waste unless accompanied by a manifest. **s.7.4** - Shall not store, collect, transport, treat or dispose of hazardous waste without authorization. **s.11** - Duty to assist inspectors. **s.15** - 2 year limitation.	**s.7.1(2)** - $5,000 maximum fine **s.7.3(2)** - $10,000 maximum fine **s.7.4(3)** - $100,000 maximum fine **s.14** - Contravention of Act where no other penalty, up to $25,000 or prison to 90 days or both.	**s.8** - A person is responsible for the acts or omissions of employees and agents within scope of their actual or apparent authority.	**s.10** - On reasonable notice, right of entry, to take documents, to test. **s.10(2)** - To enforce chemical order, no notice necessary. **s.12** - Provision for search warrant to enter private dwelling.

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
ALBERTA				
Hazardous Waste Regulation				
Alta. Reg. 505/87 (Current to 90.08.21)	**ss.9-10** - Hazardous goods must be accompanied by manifest.			
Natural Gas Processing Plant Delegation Regulations				
Alta. Reg. 88/74 **s.2** - ERCB to exercise power of Director of Pollution control under ss.6, 8 of ***Clean Air Act*** for a processing plant under ***Oil and Gas Conservation Act***. (Current to 90.08.21)	**s.3** - Offence under s.6 ***Clean Air Act*** - $5,000 maximum fine or in default, maximum - 3 months.			

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
ALBERTA				
(Proposed) ***Natural Resources Conservation Board Act*** (Bill 52)				
Purpose - To provide for an impartial review of projects affecting the natural resources of Alberta. **(Not passed in Spring 1990 legislature.)** **(Current to 90.08.21)**	**s.4 - Reviewable projects are: forest industry, recreation/tourism, metallic or quarriable mineral, water management, other projects or types prescribed by regulation.** **s.5 - No person may commence a reviewable project unless the Board has granted an approval under the Act.**			

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
ALBERTA				
Nuisances and General Sanitation Regulation				
Alta. Reg. 242/85 (under Public Health) Nuisance - means a condition injurious or dangerous to public health or which may hinder the prevention or suppression of diseases. (Current to 90.08.21)	**s.2** - No person shall create a nuisance. **s.11** - Waste storage in city, town, village or hamlet.			

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
ALBERTA ***Oil and Gas Conservation Act*** R.S.A. 1980, c.0-5, as amended. Purpose: To effect the conservation of and to prevent the waste of oil and gas resources. To promote safe and efficient practices in the development and production of oil and gas resources. (Current to 90.08.21)	**s.94(1)** - Take steps necessary to contain and clean up oil which has escaped and to prevent further escape. **s.96(1)** - Prohibited from committing waste.	**s.33** - ERCB may order that any operation at the well is suspended. **ss.34-35** - After an inquiry re suspension of well ERCB may order a suspension to continue or well or battery to be shut down. **s.94(1)-(3)** - ERCB may take steps to contain, clean up and prevent further escape of oil at the licensee's or operator's expense. **s.99** - Fines - Corporation, $300 to $1,000 1st conviction $25 to $250 subsequent/ day, and in default of payment, up to 6 mos. imprisonment.	**s.97** - Officer/Director guilty if instructs, orders, directs or causes any officer, agent or employee to contravene or to default in complying with any provision.	**s.95** - ERCB enforcement, right of entry and seizure.

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
ALBERTA ***Pipeline Act*** R.S.A. 1980, c.P-8, as amended. Purpose: To promote safe and efficient practices in the construction and operation of pipelines and the control of pollution and conservation of the environment. (Current to 90.08.21)	**s.36(1)** - In case of leak or break, shall immediately notify the ERCB of location. Where contact is made with a pipeline during any ground disturbance should be immediately stopped and permittee or licensee of the pipeline should immediately be advised of the location where the contact occurred and kind of damage. **s.36(1.1)** - The permittee or licensee of the pipeline shall then immediately notify the ERCB of the location and the kind of damage. **s.36(2)** - When leak or break in pipeline or damage to a pipeline resulting from contact has been repaired, ERCB may require submission of reports in writing.	**s.29** - ERCB may order construction or operation of a pipeline or ground disturbance suspended where it appears Act has been contravened, or where a method or practice employed or equipment or installation of pipeline or in a controlled area is improper, hazardous, inadequate or defective. **s.53(1)-(2)** - Corporations - up to $10,000/1st day, up to $5,000/subsequent day. **s.53(2)(b)** - Individual - up to $5,000/1st day, up to $2,500/subseuent day and in default prison up to 6 months.	**s.37(2)** - When a spill "Every person responsible for the escape of the substance, every pipeline operator or licensee who in the opinion of the board could be responsible ... and every officer and employee of that person, operator or licensee" shall obey Board orders.	**s.5** - ERCB may inquire into, examine and investigate any matter relating to pipeline.

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
ALBERTA				
Pipeline Act - Cont'd.				
	s.36(3) - When a pipeline transmitting oil breaks on Crown line or a forested area, licensee shall immediately report the location of the break and approximate quantity of oil escaped to Department of Forestry, Lands and Wildlife.			

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
ALBERTA ***Transportation of Dangerous Goods Control Act*** R.S.A. 1980, c.T-6.5, as amended. Purpose: To promote public safety in the transportation of dangerous goods. **s.4** - Act does not apply to handling exempted by Regulation or while under sole control of Minister of National Defence. (Current to 90.08.21)	In accordance with the Federal ***Transportation of Dangerous Goods Act***. Shall not handle offer for transport or transport any dangerous goods unless: - comply with all prescribed safety requirements - all containers, packaging and vehicles comply with prescribed safety standards and display all safety marks [s.19]. **s.5** - Ministerial Permit. **s.10** - reporting requirements. **s.17** - By-Laws for hazardous goods routes.	**s.20** - Commit offence under s.19. $50,000 or up to 2 years imprisonment/1st conviction, $100,000 or up to 2 years imprisonment/ subsequent. **s.20(2)** - Other offences, $10,000 or up to 1 year imprisonment. **s.20(3)** - 2 year limitation	**s.21** - due diligence defence. **s.22** - vicarious liability for employee or agent **s.23** - officer and director liability. Sufficient proof of the offence if it can be established that it was committed by an employee or agent of the organization whether or not the employee or agent is identified or has been prosecuted for the offence. Officer/Director guilty if directed, authorized, assented to, acquiesced in or participated in commission of the offence.	**s.7** - search powers. **s.8** - prevention powers. **s.18** - public inquiry power. **ss.6-8** - Right of inspectors to search and seize without warrant.

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
ALBERTA				
Waste Management Regulation				
Alta. Reg. 250/85 Hazardous Waste - a hazardous chemical as defined by ***Hazardous Chemicals Act*** that is or is to be disposed of as waste. Waste - refuse, garbage, any substance being disposed of.	**s.2** - Every municipality is responsible for provisions of waste management facilities. **s.3-5** - No waste management facility within radius of hospital, dwelling or food preparation site, airport. **s.7** - Permit to operate. **s.16** - Permit - nontransferable.		Owner or operator.	

SU ARY CAN AN E RONM TAL EGISLATION AND PENALTIES

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
BRITISH COLUMBIA				
Environment Management Act S.B.C. 1981, c.14, as amended. Management protection and enhancement of the environment. Covers E.I.A., environmental protection orders. (Current to 90.08.21)	**s.14(1)** - Refusal or neglect a) to provide E.I.A. b) to supply one known to be false or misleading c) refusal to comply with environmental protection order or d) emergency measures declaration e) Obstruction of entry rights.	**s.14(2)** - Contravention of 14(1)(a), (d), or (e) - fine not exceeding $10,000. **s.14(3)** - Contravention of 14(1)(b) or (c) - fine not exceeding $100,000.	**s.14(4)** - "A director or officer of the corporation who authorized, permitted or acquiesced in the offence commits the same offence and is liable to the penalty for that offence."	**s.8** - Right of entry. **s.9(3)** - Right of search and seizure by a conservation officer "anything that he has reasonable or probable grounds for believing may provide evidence".
Hazardous Waste Management Act **(*Not yet in force*)** S.B.C. 1990, c.19 **s.1** - Hazardous waste means special wastes as defined by regulation. Purpose of the Act - To ensure the development, implementation and maintenance of a comprehensive hazardous waste management system. (Current to 90.08.21)				

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
BRITISH COLUMBIA				
Transport of Dangerous Goods Act				
S.B.C. 1985, c.17, as amended. (Current to 90.08.21)	**s.5** - In accordance with the Federal ***Transportation of Dangerous Goods Act***. Shall not transport dangerous goods unless - all applicable prescribed safety requirements are complied with - all containers, packaging and means of transport comply with all prescribed safety standards and display all prescribed safety marks.	**s.16(1)** - Commits offence under s.5 (safety marks standards or requirements) or contravenes terms of permit [s.4] - $50,000 or up to 2 years imprisonment/1st conviction; up to $100,000 or prison to 2 years or both/subsequent. **s.16(2)** - Obstruction of inspector, failure to report incident - fine up to $10,000, prison for 1 year or both.	**s.18** - Sufficient to show corporation committed offence if established that it was committed by an employee whether or not the employee is identified or has been prosecuted for offence. Corporation guilty unless it can prove that offence was committed without consent and all reasonable measures were taken to prevent. **s.19** - Officer/Director guilty if directed, authorized, acquiesced in or participated in commission of offence.	**s.6** - Minister can designate analysts and inspectors. **s.8** - Right to enter, inspect, open, take samples, remove for evidence. **s.9** - Right to detain and remove. Provincial government can recover costs, where discharge has occurred or is imminent, and the government must act to protect public.

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
BRITISH COLUMBIA ***Waste Management Act*** S.B.C. 1982, c.41, as amended. Purpose - To manage and control pollution in the environment. (Current to 90.08.21)	**s.3** - Shall not introduce, cause or allow waste to be introduced into the environment unless in compliance with a permit, approval, order or the regulations. **s.3.1** - Shall keep special waste confined in accordance with regulations. **s.3.2** - Shall not construct, alter, use or operate a facility for the treatment, recycling, storage, disposal or destruction of special wastes except under and in accordance with a permit, the Act, and regulations. **s.4** - Storage - shall not store more than the prescribed amount of special waste. Transportation of Special Wastes: a) Person who produces or stores special wastes	**s.34** **(2)** - Offence under s.5(1) or 5(2) for failure to report spill - up to $200,000. **(3)** - Commit offence under ss.3 and 4 - up to $1MM. **(4)** - Knowingly insert untrue or misleading information into a manifest - up to $200,000. **(4.1)** - Obstruct or resist officer exercising duties - up to $200,000. **(5.1)** - Person holding permit to store or introduce waste into the environment who does not comply with the requirements of the permit - up to $300,000 and up to $1MM for contravening regulation re: waste discharged. **(7)** - Commit offence under s.5(3)(a) or (b) re transportation of special waste - up to $200,000; failure to comply with s.5(3)(c), up to $300,000.	**s.34(10)** - Where a corporation commits offence under Act, employee, officer, director or agent of corporation who authorized, permitted or acquiesced in the offence commits the offence, notwithstanding that the corporation is convicted. **s.34(16)** - Person liable for monetary penalty is also liable to imprisonment for up to 6 months.	**s.21** - Property - power to enter on property at a reasonable time to investigate, take records and measurements. **s.21.1** - Vehicles - to ensure compliance under legislation an officer may request the opening and inspection of any road or rail vehicle. **s.21.2** - Upon reasonable grounds an officer may make an emergency inspection.

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
BRITISH COLUMBIA ***Waste Management Act*** - Cont'd.	- shall not allow more than a prescribed amount to be transported from the property unless he completes the manifest in the manner prescribed - shall ensure that the person transporting more than the amount of special waste has a license for that purpose - shall not cause or allow more than the prescribed amount of special waste to be transported to a place without authorization to do so [s.5(1)]. b) Person who transports special waste - shall not transport more than the prescribed amount unless carrying with him a completed manifest [s.5(2)].	**(8) and (9)** - Contravene order or plan given, made or imposed under this Act - up to $300,000 **(13)** - Where offence continues for more than one day, separate fines may be imposed for each day the offence continues, each not to exceed the maximum fine for offence. **s.34.2** - Intentional damage - fine up to $3MM or prison for 3 years or both.		

SUMMARY OF CANADIAN ENVIRONMENTAL LEGISLATION AND PENALTIES

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
MANITOBA				
Environment Act				
S.M. 1987-88, c.26 Purpose - To develop and maintain an environmental management system which will ensure the protection and conservation of natural environment. (Current to 90.08.21)	**ss.10, 11, 12** - License required for all classes of development. a) Oil and Salt Water - an accident involving oil and salt water resulting from a break or leak in a wellhead, pipeline or other installation should be reported as soon as possible (in all cases within 24 hours) to the Petroleum Branch of the Department of Energy and Mines b) All other environmental accidents should be reported immediately after the occurrence to the Manitoba Department of Environment and Workplace Safety and Health.	**s.33(1)** - Individuals - $50,000 or up to 6 months imprisonment/for each day 1st offence continues, $100,000/for subsequent offence or up to 1 year imprisonment. - If unwilling or unable to remedy situation or condition, judge may suspend or revoke all or part of the environmental licenses or permits under which individual operates.	**s.35** - An officer or Director may be found guilty if directed, authorized, acquiesced in or participated in the commission of offence.	**ss.20 and 21** - At a reasonable time an officer may enter without a warrant to conduct inspections and make copies of documents. **s.21(1)** - Entry with warrant. **s.21(2)** - Action without a warrant.

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
MANITOBA				
Environment Act - Cont'd.				
	s.33(2) - Corporations - up to $500,000/1st per day offence continues, up to $1MM/subsequent. If unwilling or unable to remedy situation or condition judge may suspend or revoke all or part of the environmental licenses or permits under which the corporation operates. **s.36** - Other penalties may be required to - refrain from committing any further offence or from causing further damage - clean or restore the environment from damage caused - pay damages or make restitution to any person who suffered damages - pay an additional fine in an amount no greater than the monetary benefit acquired as a result of the offence, notwithstanding any maximum fine elsewhere provided.			

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
MANITOBA				
Pesticides and Fertilizers Control Act R.S.M. 1987, c.P40 (Current to 90.08.21)	**s.2(1)** - Distributor of pesticides or fertilizers must obtain license. **s.2(2)** - "No person shall act as a commercial applicator unless he first obtains a license." **s.2(4)** - Insurance is required. **s.3** - No sale to unlicensed retailers. **s.7** - Failure to comply with Act or regulations, willfully obstructs inspector.	**s.7(1)** - Fine of not less than $100 or more than $1,000 or to imprisonment for not less than 60 days, or more than 6 months, or to both. **s.7(2)** - In addition, the Minister may deny, suspend or revoke the license or permit of any person convicted under s.7(1).		**s.4(1)** - "Minister may appoint inspectors who may at any reasonable time and without warrant, enter any business premises", or premises "where business records are kept, and make copies of . . documents concerning the supply, sale, distribution or use of pesticides or fertilizers", may inspect and take samples, investigate breaches, or may carry out acts required by the Minister. **s.4(2)** - Justice may issue a warrant to enter and seize when there are reasonable and probable grounds to believe an offence has or is occurring. **s.4(3)** - The Minister may cause the destruction of contaminated material.

SUMMARY OF CANADIAN ENVIRONMENTAL LEGISLATION AND PENALTIES

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
NEW BRUNSWICK				
Clean Environment Act				
R.S.N.B. 1973, c.C-6, as amended by S.N.B. 1989 c.52. Environment - "air, water, or soil" Contaminant - "any solid, liquid, gas, odour, heat, sound, vibration, radiation, or combination of any of them present in the environment" that is foreign to it, affects its natural quality, endangers life or safety, or that is prescribed by regulation to be a contaminant and includes pesticides. (Current to 90.08.21)	**s.5.3** - "No person shall discharge, emit, leave, deposit or throw any contaminant or waste ... into the environment if it affects the natural quality of the environment, endangers health or safety, causes damage to property or plant life **s.11** - No well drilling, or operation incidental to the reconditioning or abandonment of a well without valid licence **s.25** - Must give reasonable assistance to inspector **s.26** - No person shall obstruct or hinder an inspector **s.27** - No making false or misleading statements.	**s.33** - Non-compliance with Act, regulations or orders issued under the Act - for a corporation, fine $1,000 to $1MM.	**s.25** - "The owner or person in charge of any area, land, place or premises and any employees or agents of the owner or person in charge shall give all reasonable assistance" ... to an inspector **s.34** - Every person other than an individual who commits an offence commits an absolute liability offence.	**s.24** - An inspector at any reasonable time and upon presentation of proof of identification may enter, inspect and test, take samples **s.24.1** - Inspector shall not enter a private dwelling unless it is an emergency situation, has the consent of occupier or obtains a warrant **s.24.2** - Inspector may detain any substance, sample, document for evidential purposes.

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
NEW BRUNSWICK ***Pesticides Control Act*** R.S.N.B. 1973, c.P-8 Pesticide - "any product, device, organism, substance or thing or combination" used to control pests or, "altering the growth, development or characteristics of any living plant that is not a pest ..." (Current to 90.08.22)	**s.9** - Where sale restricted no selling of that pesticide except in accordance with specified conditions **s.14** - No offering for sale, selling or supplying pesticides without a vendor's licence **s.15** - No person shall operate a business or provide or offer to provide a service involving pesticides without a pesticide operator's licence **s.16** - No application of pesticides without a certificate or permit **s.18** - No use of pesticides for purposes other than which they were sold **s.19** - No submerging pesticide containers contrary to regulations **s.20** - No discharging of pesticides in a body of water **s.21** - No storing or transporting of pesticides in a manner injurious to life	**s.30(1)** - Contravention of s.9, 14, 15, 22, 23, 24.1, 27 - fine of not more than $1,000 or to imprisonment for not more than 100 days or to both/day offence continues **s.30(1.1)** - Contravention of 16, 18, 19, 21, 24 or 30.1 or an order made by the Minister - fine of not more than $50,000 or imprisonment for not more than a year, or to both/day offence continues **s.30.1(2)** - Clean-up costs are recoverable by the Province.	**s.30(1.3)** - "In a prosecution for an offence ... it is sufficient proof ... to establish that it was committed by an employee or agent of the accused, whether or not the employee or agent is identified or has been prosecuted ... unless the accused establishes that the offence was committed without his knowledge or consent and that he exercised all due diligence to prevent its commission." **s.30.1** - Where discharge occurs "a person who at any material time owns the pesticide or substance, or has the charge, management or control of it, or causes or contributes to the deposit or discharge" has a duty to inform and to take mitigating action.	**s.27** - Where reasonable cause, "an inspector may, at any reasonable time, enter and inspect any premises or vehicle," take samples, examine documents.

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
NEW BRUNSWICK				
***Pesticides Control Act* - Cont'd.**	**s.22-23** - No selling of pesticides in unauthorized containers. **s.24** - No disposing of pesticides contrary to regulations. **s.27** - No obstruction of inspector. **s.30.1** - Where discharge occurs, duty to notify Director immediately, and take measures as prescribed by regulation.		**s.30.1(3)** - Liability for clean-up costs "is absolute and does not depend on proof of fault or negligence." No such person is liable if discharge caused naturally in exceptional circumstances or "by person other than a person for whose wrongful act or omission he is by law responsible."	

SUMMARY OF CANADIAN ENVIRONMENTAL LEGISLATION AND PENALTIES

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
NEWFOUNDLAND ***Department of Environment and Lands Act*** 1989, S.N. 1989, c.21 Pollution: "any alteration of the physical, chemical, biological or aesthetic properties of air, soil or waters" which will render them harmful to safety or less useful for lawful purposes. (Current to 90.08.21)	**s.24(1)** - For construction of a sewage work, or industrial or processing work, requirement for approval by the Minister **s.25** - No discharge or deposit of "material of any kind into a body of water or on a shore or bank ... or in a place that may cause pollution or impair the quality of water for a beneficial use." **s.45** - No obstruction	**s.33** - Penalties prescribed by regulations made under s.33(8) - No fines separate from the Act for air and water pollution. - Storage and Handling of Gasoline Regulations, s.32 - fine not exceeding $10,000/day offence continues - Misfuelling of Vehicles - fine not exceeding $1,000/day offence continues **s.41** - Where pollution occurs, remedial action costs recoverable by the Province from the person responsible for pollution occurrence **s.47** - Non-compliance with Act or regulations, where not provided for elsewhere, for a corporation: fine of not more than $25,000/day offence occurs	**s.28(2)** - Stop orders served on "owner or person in charge of the works or the operators."	**s.24(2)** - Where no approval obtained for construction of a sewage, industrial or processing work, the Minister may order an investigation, or may order changes **s.34** - Inspector may "at all reasonable times ... to determine compliance ... enter into and go upon land or a body of water," and inspect or test **s.35** - Authority to inspect records

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
NEWFOUNDLAND ***Pesticides Control Act*** S.N. 1983, c.52 Pesticide - "Any substance or mixture of substances used for the destruction or control of insects, birds, rodents or other pests or fungi." (Current to 90.08.21)	**s.4** - No person shall sell, store, use a pesticide without a licence or unless exempted under the regulations **s.5** - No licence unless the person has a subsisting liability insurance policy **s.8** - No storage of pesticide unless in an approved container **s.9** - No storage or transport of pesticides so as to contaminate food or drink **s.10** - No handling unsafely **s.11** - No disposal except at a prescribed site **s.12** - No washing of containers in a body of water **s.20** - No obstruction of inspector	**s.25** - Contravention of Act or regulations - fine not exceeding $10,000/day offence continues or imprisonment for 90 days or both	**s.6(2)** - "A licence holder is responsible for the activities of an unlicensed assistant, in connection with the use, storage, application or sale of pesticides." **s.6(3)** - Unlicensed assistant must comply with Act and regulations. **s.15** - Order to take action to "the person in charge of or responsible for the operation." **s.18** - Stop order issued "to the person responsible for the pesticide."	**s.17** - Inspectors shall have the power to take samples, examine records.

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
NEWFOUNDLAND				
Waste Material (Disposal) Act S.N. 1973, no. 82 Power over the establishment, construction, operation and management of waste disposal sites and waste management systems. (Current to 90.08.22)	**s.10**(2) - Arrangements must be made by persons or firms engaged in commercial enterprises for disposal of waste from the premises **s.19** - Prohibition against deposit of waste or use of system except in accordance with terms of certificate **s.20** - No removal of waste from a waste disposal site without approval.	**s.19(3)** - Failure to comply with order for removal of waste - person ordered may be charged for the cost "which may be recovered as a debt due to Her Majesty, with costs, in any court". **s.22** - Violation of the Act, regulations, or conditions of any certificate - fine not exceeding $2,000/day offence continues.	**s.19** - Order for removal of waste to "the occupant or the person having charge and control of the land or land covered by water, or building or structures on or in which the waste was so disposed or the person who disposed of the waste." **s.21** - Minister may order owner to bring site into conformity with the Act, and the owner may be charged with the cost.	**s.23(l)(j)** - Provision for regulations to be made regulating inspection but none promulgated.
Waters Protection Act R.S.N. 1970, c.394 Care of all inland waters for the purposes of public health. (Current to 90.08.22)	**s.6** - No person shall build a house, establish a farm, cemetery or sewage disposal arrangement upon the watershed of any body of water without prior permission of the Minister.	**s.8** - Disobeying any Ministerial order or contravention of the Act - fine not exceeding $50, or in default, 7 days imprisonment/1st offence; not exceeding $500 or in default, 3 months/subsequent offence. Each week of continuance shall be deemed a separate offence.	**s.4** - The Minister may order "the authority or person having control in the circumstances to remove or destroy such thing or to amend or prevent such condition or to desist from such practice."	**s.3** - "The Minister may, by his officers at all times approach and examine any waters whether on public or on private property" may examine the lands forming the watershed, any buildings or environment on such watershed, and take samples.

SUMMARY OF CANADIAN ENVIRONMENTAL LEGISLATION AND PENALTIES

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
NORTHWEST TERRITORIES				
Environmental Protection Act R.S.N.W.T. 1974, c.E-3 Protection of the environment, including air, water, ice, snow and land and all animal and plant life therein. (Current to 90.08.22)	**s.6** - "No person shall discharge or permit the discharge of any contaminant into the environment that causes or contributes or is likely to cause or contribute to substantial impairment of the quality of the environment or adversely affects or is likely to adversely affect the health, safety or comfort of any person." **s.10** - "No person shall permit premises "owned, occupied or abandoned by him to be unsightly ..."	**s.8** - Any person who discharges or permits the discharge of a contaminant may be ordered to repair the damage, and where he fails to repair, is liable for clean-up costs **s.12(1)** - Contravention of s.6, or a stop or clean-up order - fine not exceeding $1,000 or prison for not more than 6 months or both/day offence continues **s.12(2)** - Non-compliance with a protection order under s.5 - fine not exceeding $500 or prison for not more than 3 months or both/day offence continues.	**s.3(2)** - Ordinance does not apply to any person authorized by Act of the Federal Parliament" to do those things that but for such Act or Ordinance are in contravention of this Ordinance." **s.5** - Protection order may be issued, requiring "any person" to install safeguards to prevent the discharge of contaminants, to transport or store any contaminant in an approved manner, or to have on hand any necessary equipment needed to alleviate the damage **s.17(3)** - Owner or person in charge shall give Inspector all reasonable assistance, and furnish information required.	**s.17** - Inspector may "at any reasonable time enter any area, place or premises other than a private dwelling."

SUMMARY OF CANADIAN ENVIRONMENTAL LEGISLATION AND PENALTIES

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
NOVA SCOTIA				
Dangerous Goods and Hazardous Wastes Management Act				
S.N.S. 1986, c.7, as amended. Act applies to the handling (but not transportation) of dangerous goods for any purpose other than domestic. (Current to 90.07.25)	**s.5** - Requirement to notify Minister of location and quantity of hazardous waste. **s.6** - No person shall store, treat, dispose of or re-process a hazardous waste except at approved facilities. **s.8A(d)** - No obstruction of inspection or furnishing false information.	**s.11** - Non-compliance with Act or regulations, or Ministerial directive, fine not exceeding $50,000 or in default to imprisonment not exceeding one year. For subsequent convictions, fine of not more than $75,000 or in default prison not exceeding 2 years/day offence continues.	**s.4** - Person responsible for dangerous goods shall notify the Minister regarding this location, quantity, general purpose, and precautions being taken **s.7** - Minister may direct person responsible for the dangerous goods to prepare and submit a written contingency plan respecting handling or disposing of dangerous goods **s.8** - Where accidental discharge, person responsible shall, "immediately on becoming aware of the occurrence, notify the Minister, and take measures" to remedy the effects.	**s.8A** - Same powers as ***Environmental Protection Act***.

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
NOVA SCOTIA ***Environmental Protection Act***				
S.N.S. 1973, c.6 Environment - "The air, land and water or a combination or part thereof within the jurisdiction of the Province." Purpose - "To provide for the preservation and protection of the environment." (Current to 90.08.22)	**s.23(1)** - "No person shall own, occupy, operate or be responsible for the operation of a plant, structure, facility, undertaking or thing that discharged, releases, deposits, drains, emits, or threatens or allows the emission of waste into the environment, without a permit **s.23(2)** - No removal of material **s.28** - No construction or altering of facility likely to cause pollution without submitting plans to the Minister and getting his approval **s.43(3)** - No obstruction of inspectors.	**s.48** - Contravention of Act or regulations, fine of not more than $50,000 or in default imprisonment not exceeding one year/1st conviction; $75,000 or in default imprisonment not exceeding 2 years/subsequent each day offence continues **s.48(2)** - In addition to penalty, the court may order compliance with the Act or regulations **s.54** - Costs of remedial action or damages are recoverable from the accused	**s.23(8)** - When an application is made for a permit, the Minister may "require additional plans or information", or "require the applicant to give security" **s.25** - "The Minister may require a person discharging waste into the environment to measure or monitor the discharge", and report results **s.26** - A stop order may require the person responsible for pollution to "install, replace or alter equipment or thing" causing the pollution **s.43(2)** - Required to co-operate with inspector **s.46** - In a prosecution employee is liable unless he "establishes that the offence was committed without his knowledge or consent and that he exercised all reasonable diligence to prevent its commission"	**s.43** - An inspector at any reasonable time and upon presentation of a certificate may enter and search premises and make examinations, tests and inquiries.

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
NOVA SCOTIA ***Pest Control Products (Nova Scotia) Act*** S.N.S. 1986, c.16 Purpose - To regulate the sale, handling, use, storage, transportation and disposal of pest control products. (Current to 90.08.22)	**s.14** - No use of pest control products without a permit **s.16** - No person shall handle or use a pest control product or container contrary to the Act or in a manner that may cause contamination **ss.19(2)** - No obstruction of inspector.	**s.23** - Costs of remedial action may be paid out of the bond or security required under s.14 **s.27** - Contravention of Act or regulations - fine of not more than $50,000 or in default, imprisonment not more than a year/1st $75,000 or in default 2 years/ subsequent, each day offence continues.	**s.6(2)** - "It is the responsibility of all persons to ensure that sale, use, handling, storage, transportation and disposal of pest control products does not result in contamination."	**s.24** - Inspector may at any reasonable time, enter, search, take samples, examine books or documents.

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
NOVA SCOTIA				
Water Act				
R.S.N.S. 1967, c.335 Supervision of all water courses in Provincial jurisdiction excluding fishing rights. (Current to 90.08.22)	**s.16** - No person "shall discharge or deposit or cause or permit a discharge or deposit of any kind into or in any well, aquifer, lake, river stream, ... or other water or watercourse ..., that may cause pollution or impair the quality of the water ..."	**s.20** - Contravention of Act, regulations or Ministerial order - fine of not more than $50,000 or in default imprisonment not more than 1 year/1st conviction, not more than $70,000 or in default imprisonment not more than 2 years/subsequent, each day offence continues **s.3** - Minister may authorize payment of compensation to any person whose rights are injuriously affected.	**s.18** - When any alteration of a watercourse or the water flow therein is contemplated, the plans must be submitted to and approved by the Minister **s.19(5)** - Compensation for injurious affection owed by "the person operating the water work."	**s.7(2)** - Right to inspect works, books, accounts, papers and records of any person using a watercourse **s.19** - Right of inspector to "enter into and upon the lands or buildings used for commercial, industrial or public purposes" and make necessary investigations.

SUMMARY OF CANADIAN ENVIRONMENTAL LEGISLATION AND PENALTIES

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
ONTARIO				
Energy Act				
R.S.O. 1980, c.139 (Current to 90.08.22)	**s.5** - No obstruction of inspectors **s.11** - Installation of equipment must be in accordance with regulations **s.17** - No activation of pipeline unless examined and inspected **s.18** - Duty to inquire before excavation **s.19** - No interference with pipeline **s.27** - Non-compliance with Act or regulations, making false statement, contravention of term of licence or order of inspector or Minister.	**s.27** - Fine up to $10,000 or imprisonment up to a year, or both.	**s.4** - Required to produce documents for inspectors **s.20** - Duty of employer to obtain compliance	**ss.3-8** - May enter "upon any premises at any time without a warrant", seize "any work or appliance or part thereof"

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
ONTARIO ***Environmental Protection Act*** R.S.O. 1980, c.141, as amended. **s.2** - Protection and conservation of total "natural environment." **s.1** - Environment all inclusive - adverse effects, safety, enjoyment. (Current to 90.08.22)	**s.5** - No discharge of any contaminants in amounts excessive to those prescribed by regulation. **s.13** - No discharge that "causes or likely to cause an adverse effect". **s.39-40** - No deposit of waste except on approved site; no use of waste management equipment unless approved **s.72** - Sewage systems must be approved **s.75** - No litter **s.76** - No use or sale of unapproved packaging. **s.150** - Power to prohibit any person with an interest in the property from dealing with it in any way without first giving a copy of the order or decision affecting the property to each person acquiring an interest. **s.150(4)** - Prohibited property dealings voidable.	**s.78** - Litter - corporation $2,000/1st conviction $5,000/subsequent **s.78(a)** - Containers - $5,000/1st conviction $10,000/subsequent each day offence continues **s.124e** - Director may order to pay costs **s.124l** - Costs specified in order to pay may be collected as taxes. **s.146(4)** - Contravention of Act, failure to comply with order - $50,000/1st conviction, $100,000/ subsequent conviction **s.146a** - Pollution - $2000 to $200,000/1st conviction; $4000 to $400,000/subsequent each day or part thereof the offence continues **s.147(2)** - Waste - $100,000/1st conviction $200,000/subsequent each day offence continues **s.147(4)** - Adverse effect $2000 - $2MM/1st conviction; $4000 - $2MM/subsequent.	**s.7(1)** - a) Owner or previous owner of source of contaminant b) Person who is or was in occupation of the source of the contaminant c) A person who has or had the charge, management or control of the source of the contaminant. **s.87(2)** - Right to compensation for loss, damage, clean-up costs and expenses from "the owner of the pollutant and the person having control of the pollutant." **s.87(3-4)** - Qualifications and exceptions **s.147a** - Duty to take all reasonable care to prevent unlawful discharge **s.147a(3)** - Liable to conviction whether or not the corporation has been prosecuted or convicted.	**s.124d** - Power to enter without a warrant if: a) entry made with consent of occupier or owner b) delay would result in danger to safety of a person, serious risk of impairment to the environment **ss.126-130** - Power of provincial officers to enter, take samples, without a warrant or court order, at any time.

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
ONTARIO				
Gasoline Handling Act				
R.S.O. 1980, c.185 Control of gasoline or petroleum products from private or retail outlets, marinas, bulk plants. (Current to 90.08.22)	**s.17** - Contravenes Act, makes false statement, fails to carry out instructions of inspector.	(Amended by S.O. 1989, c.72 in force March 31, 1990.) **s.17** - Not more than $25,000	**s.13** - Employers must take reasonable precautions to ensure compliance **Reg. 439, s.9(6-7)** - In event of product escape, the operator, owner, or owner's authorized representative shall take immediate corrective action, and notify the nearest inspector ASAP **Reg. 439, s.19(8)** - Where fire or explosion, owner and operator shall notify Director ASAP, and supply information upon request.	**Reg. 439, s.8(37)** - Where a leak is suspected or where the Director of Fuels Safety Branch requests, owners shall make facilities available for testing.

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
ONTARIO				
Lakes and Rivers Improvement Act				
R.S.O. 1980, c.229 To provide for the use of the waters of lakes and rivers, to regulate improvements, to provide for preservation and protection of such waters. (Current to 90.08.22)	**s.3(3)** - Contravention of Act **s.35** - Not topping off branches of trees (ie. obstruction of lake or river) **s.36** - Failure to comply with order under s.35 **s.38** - Depositing or discharging refuse into lake. Failure to comply with order under this section.	**s.3(3)** - Fine of not more than $5,000 **s.35** - Not more than $10 **s.36** - Not more than $50/day **s.38** - Not less than $200. Failure to comply with order under this section - $50/day.	**s.35** - "Employer" **s.38** - "Owner or occupier of mill.	Nothing in the Act.

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
ONTARIO *Ontario Water Resources Act* R.S.O. 1980, c.361 Any works for the collection, production, treatment, storage, supply and distribution of water. (Current to 90.08.22)	**s.10(4)** - Hindering the Inspector **s.16** - Discharge of polluting material into water or on shore that impairs the quality of the water **s.19(2)** - Impairment of the quality of the water of defined areas **s.20(3-7)** - Taking of water which interferes with public or private interest in the water **s.64a** - Power to prohibit any person with an interest in land from dealing with the land without giving copy of any order or decision issued with regard to it to each person acquiring an interest in the land **s.64a(5)** - Prohibited dealings with land voidable **ss.66-67** - Contravention of Act	**s.48e** - Director may issue an order to pay costs **s.48l** - Costs specified in order may be collected as taxes **ss.66-67** - Contravention of Act, failure to comply with an order, contravening a term or condition of a licence - for a corporation $50,000/1st conviction, $100,000/subsequent. **s.68** - Conviction under s.16 or s.19, for a corporation up to $100,000/1st conviction, $200,000/subsequent conviction.	**s.18** - "Person who owns, manages, or has control of a sewage works, water works or other facility which may discharge material into a water or watercourse that may impair the quality of the water" may be ordered by Director to take measures to alleviate effects of impairment of the water quality. **ss.23, 24** - Where water works or sewage works are undertaken without approval Director may order "the person or his successor or assignee" to afford facilities, make changes considered necessary, at his own expense.	**s.48d** - Power to enter without a warrant if entry made with consent of occupier or owner or if delay would result in danger to safety of any person or serious impairment of the auality of the environment.

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
ONTARIO				
Pesticides Act				
R.S.O. 1980, c.376 Any organism, substance or thing used to control pests. (Current to 90.08.22)	**s.4** - No discharge, or cause or permit discharge of a pesticide into the natural environment. **s.6** - No sale or transfer of pesticide without a licence. **s.7** - No extermination with a pesticide without a permit.	(Penalties amended S.O. 1989, c.72, in force March 31, 1990.) **s.34a** - Contravention of Act, failure to comply with order, or with term or condition of licence or permit - for a corporation $50,000/1st conviction, $100,000/subsequent conviction. **s.34b** - Penalty re monetary benefit. Fine may be increased by an amount equal to the amount of the monetary benefit acquired. **s.34c** - Conviction under the Act, for contravention of s.4, or stop order made under s.20; for a corporation $100,000/1st conviction, $200,000/subsequent conviction.	**s.8** - An act or thing done or omitted to be done by an officer, official, employee or agent of a corporation in the course of employment, shall be deemed to be done by the corporation **s.34 (g)(1)** - Every officer or Director "has a duty to take all reasonable care to prevent the corporation from causing or permitting such unlawful effect." **s.34(g)(4)** - Director or officer is liable to conviction whether or not the corporation has been prosecuted or convicted.	**s.19** - Provincial officer may without a warrant or court order, at any reasonable time, make inspections, including entering any place, stopping any vehicle, taking samples, requiring production of documents.

SUMMARY OF CANADIAN ENVIRONMENTAL LEGISLATION AND PENALTIES

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
PRINCE EDWARD ISLAND				
Environmental Protection Act S.P.E.I. 1988, c.19 Broad in scope - contaminant includes any solid, liquid gas, waste, odour, sound or combination foreign to or in excess of natural constituents of environment. **s.2** - Purpose - to manage, protect and enhance the environment. (Current 90.08.22)	**s.9** - No person shall initiate any undertaking without filing a proposal and obtaining written approval **s.10** - Permit required for alteration of a watercourse **s.12** - No drilling or construction of a well except in accordance with the regulation **s.13** - No establishing of waste treatment or water supply system without approval **s.20** - No person shall discharge or cause or permit to be discharged any contaminant into the environment **s.24** - No littering **s.26** - No person shall knowingly give false information. **s.27** - No obstruction of any person carrying on enforcement.	**s.32** - Contravention of Act or regulations - for corporation, $1,000 - $50,000, plus restitution/ day of offence.	**s.21** - "Every person who ... owns or has control of a contaminant" shall notify Department and take remedial measures **s.32(2)** - Personal liability of corporate officers, who "directed, authorized, assented to, acquiesced in or participated in" the commission of an offence.	**s.7(1)** - Minister may by order permit inspection at a designated time, testing and sampling **s.7(4)** - Environment officer may at any time, without notice enter upon and examine any land, air, water, excluding structures.

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
PRINCE EDWARD ISLAND ***Pesticides Control Act*** S.P.E.I. 1984, c.29 (Current to 90.08.22)	**s.2** - No sale or supply of pesticides that do not meet the standards prescribed by regulation **s.3** - No illegal use of pesticides **s.5** - No possession of pesticides except in prescribed container **s.21** - Must assist inspectors, no obstruction	**s.23** - Fine of not more than $1,000 or imprisonment for 90 days, or to both	**s.21** - "Owner or person in charge of any land, premises, thing or substance" must assist inspector and not obstruct	**s.19** - Inspector may "at any reasonable time enter upon and inspect any land, premises, vehicles, equipment, record, document or other property" and take samples **s.20** - Warrant needed for entering private dwelling

SUMMARY OF CANADIAN ENVIRONMENTAL LEGISLATION AND PENALTIES

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
QUEBEC				
Environment Quality Act				
R.S.Q. 1977, c.Q-2 Contaminant - includes 'a solid, liquid or gaseous matter, a micro-organism, a sound, a vibration, rays, heat, an odour, a radiation ... likely to alter the quality of environment." Environment - water, atmosphere, soil or combination, or generally "the ambient milieu with which living species have dynamic relations." (Current to 90.08.22)	**s.20** - No one may emit, deposit, issue or discharge contaminant in greater quantity than is regulated, or that "is likely to affect the life, health, safety, welfare or comfort of human beings" or "to impair the quality of the soil, vegetation, wildlife or property." **s.21** - Whoever is responsible for the accidental contamination must notify the Minister without delay **s.22** - "No one may erect or alter a structure, undertake to operate an industry, carry on an activity or use an industrial process ..." if likely to contaminate, without the Minister's authorization. **s.31.1** -No one may undertake any activity ... without following the environmental impact assessment and review procedure.	**s.106.1** - Contravention of ss.20-22, 31.1, 68, 95, 121 or order of the Minister under the Act - for corporations, fine $12,000 to $500,000/1st conviction, $500,000 - $1MM/subsequent. **s.106.2** - Contravention of provisions re: de-pollution attestions - for a corporation, $10,000 - $250,000/1st conviction, $20,000 - $500,000/ subsequent. **s.107** - Refusal to file required documents, for a corporation, $1,500 - $7,200/1st conviction, $3,000 - $120,000/ subsequent. **s.108** - Unauthorized waste sites, for a corporation, $1,000 - $30,000/1st offence, $4,000 - $100,000/ subsequent. **s.109** - Contravention of Act where no other penalty imposed, $300 - $5,000.	**s.21** - Accidents - "whoever is responsible for the accidental presence in the environment of a contaminant." **ss.31.12 - 31.31** - Requirements for holders of de-pollution attestations re discharge standards, de-contamination programs, emergency measures to be taken, records to be kept, etc. **s.109.3** - "Every director or officer of a corporation who, by means of an order or authorization or through his advice or encouragement, leads the corporation" ... to contaminate, commits an offence is liable to same penalties as in s.106.1. **s.112** - Proof that offence has been committed by an agent, mandatory or employee of another is sufficient to establish that it has been committed by the latter" ... unless done	**s.119** - Right of entry at any reasonable time, to anything other than a dwelling house, and right to take samples, examine records **s.120** - Power to require information **s.120.1** - Search warrants authorized where reasonable grounds that an offence is being or has been committed, for entry between 7 a.m. and 8 p.m., and taking records and samples. Entry without a warrant if delay endangers life or safety. **s.123** - The Minister or any investigator designated by him, may inquire into any matter contemplated by the Act or regulations. Same powers and immunities of Commissioners respecting public inquiry commissions.

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
QUEBEC				
Environment Quality Act - Cont'd.				
	s.31.11 - (Not yet in force) - No discharge of contaminant if Minister has refused to issue a de-pollution attestation. **s.31.30 and s.31.31** - (Not yet in force) When de-pollution attestation has been revoked or suspended, or holder of it ceases to operate, no discharge of contaminant allowed. **ss.31.42 - 31.51** - Broad powers given to the Minister to order decontamination of sites during operation and the responsible party to recover, remove, collect or neutralize the contaminant. **s.95** - Prohibition against abusive noise inside or outside a building. **s.95.1** - No undertaking of environmentally sensitive projects without filing with the Minister plans and specifications. **s.121** - No obstruction of inspectors.	**s.109.1** - Government may prescribe by regulation that an offence against the Act respecting a contaminant is liable to a fine, for a corporation, $25,000 - $500,000 1st conviction, $50,000 - $1M subsequent. **s.109.2** - Party to an offence gets the same penalty. **s.113** - Restitution provisions. **s.115** - Restoration at expense of offender. **s.129** - Contravention of regulations, same penalties as s.109.	without his consent, and despite measures taken to prevent its commission.	

SUMMARY OF CANADIAN IRONMENTAL LEGISLATION AND PENALTIES

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
SASKATCHEWAN				
Clean Air Act				
S.S. 1986-87-88, c.C-12.1, as amended. Air Pollution (Current to 90.08.22).	**s.5** - No person shall operate an industrial source, or alter it in a way that affects air emissions without a permit. **s.6** - Exceptions to permit requirement include oil and gas industry. **s.13(2)** - Duty to report full details of air emission emergency within 7 days. **s.20** - No person shall operate an industrial source under conditions which contribute to soil and water pollution by air contaminants.	**s.22** - Contravention of Act or regulations, failure to comply with permit, or control order, making false or misleading statements for a corporation.	**s.22(2)** - Any officer, Director or agent of the corporation who directed, authorized, assented to, acquiesced in or participated in the commission of the offence is guilty, and liable to the punishment provided, whether or not the corporation has been prosecuted or convicted.	

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
SASKATCHEWAN ***Environmental Management and Protection Act***				
ss. 1983-84, c.E-10.2, as amended. Purpose - To provide for protection nd conservation of natural environment, prohibiting discharge of contaminants into the environment. (Current to 90.08.22)	**s.9** - Duty to report. **s.17** - Shall not cause or allow any contaminant to be discharged, deposited, drained or released where there is a reasonable possibility it may change the quality of any water or cause water pollution without holding a valid permit.	**s.4** - May be ordered to take any measure the Minister considers necessary to protect or restore the environment. **ss.7(1)(b) and 8(2)(a)** - Clean-up costs recoverable. **s.13(2)** - Investigation - fine imposed to recover costs and expenses incurred with respect to investigation into discharge. **s.35(1)** - Contravene provision of Act or fail to comply with an order of the Minister - fine not exceeding $1MM, prison up to 3 years or both.	**s.8(2)(a)** - "The owner of the pollutant or the person having control of the pollutant" is liable for clean-up costs. **s.9** - "The owner of a pollutant, the person having control of a pollutant, any person on whose property a pollutant is located, or any other person who has knowledge relating to the pollutant or its discharge, shall furnish and maintain any information" re: discharge required under the Act. **s.13** - Civil liability of owner of pollutant and person having control of pollutant for loss or damage without proof of fault, negligence or willfull intent; unless he establishes he took all reasonable steps to prevent discharge.	**s.3** - Minister may make any investigation necessary re: discharge.

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
SASKATCHEWAN *Environmental Management and Protection Act* - Cont'd.			s.35(2) - Any officer, Director or agent of the corporation who directed, authorized, assented to, acquiesced in or participated in the commission of the offence is guilty, liable to the punishment provided, whether or not the corporation has been prosecuted or convicted.	

SUMMARY OF CANADIAN ENVIRONMENTAL LEGISLATION AND PENALTIES

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
YUKON				
SEE FEDERAL:				
Arctic Waters Pollution Prevention Act For Arctic waters and land surrounding the Arctic waters.	NOTE: Yukon Minister of Renewable Resources issued a discussion paper Protecting Our Yukon Environment (August 1990). They are in the process of drafting a comprehensive Environment Act.			
Canadian Environmental Protection Act For projects under Federal jurisdiction.				
Fisheries Act				
Northern Inland Waters Act For Yukon, Liard, Alsek, Peel and Porcupine Rivers, tributaries and basins, plus all waters and tributaries draining into the Beaufort Sea.				
Territorial Lands Act For oil and gas exploration, drilling and production.				

LEGISLATION	DUTY/OFFENCES	PENALTIES	DIRECTORS /EMPLOYEES LIABILITY	SEARCH POWER
YUKON				
Dangerous Goods Transportation Act R.S.Y.T. 1986, c.39 (Current to 90.08.22)	**s.5** - No person shall transport any dangerous goods unless all safety requirements are complied with. **s.6** - Containers must conform to safety standards. **s.8** - When an accident occurs, duty to report as soon as possible. **s.12(3)** - Duty to give inspector assistance. **s.15** - No obstruction of inspectors. **s.23** - 2 year limitation period.	**s.13** - Goods, containers or vehicles may be detained. **s.18** - Contravention of ss.5 or 6 - fine up to $50,000/1st, to $100,000/ subsequent, prison up to 2 years or both.	**s.12(3)** - "The owner or person who has the charge, management or control of any container packaging or vehicle" ... must assist inspector. **s.20** - Due diligence defence. **s.22** - Every officer, Director or agent of a corporation who directs, authorizes, assents to, acquiesces in or participates in the commission of an offence is guilty, whether or not the corporation has been prosecuted or convicted.	**s.8** - Inspector shall have access to any place or property, and may do all reasonable things. **s.12** - Inspector may stop and inspect any vehicle, take samples or any documents.
Gasoline Handling Act R.S.Y.T. 1986, c.79 Petroleum products handling and storage. (Current to 90.08.22)	**s.6** - No operation of a service station marina, bulk plant or transportation of gasoline or associated product without a safety certificate. **s.8(4)** - Occupant and his agents and employees must assist inspector.	**s.10** - Contravention of Act, making false statement, obstructing inspector, fine up to $500, prison up to 6 months or both.	**s.7** - Every person who employs another person in the handling of gasoline or associated product has duty to take all reasonable precautions to ensure compliance.	**s.8** - Right to enter, inspect, test, take samples.

IMPLICATIONS OF THE PROPOSED CANADIAN ENVIRONMENTAL ASSESSMENT ACT (BILL C-78) FOR PIPELINES IN CANADA

by

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ABSTRACT

Regulation of the pipeline industry from an environmental perspective is changing as a result of federal court decisions interpreting the 1984 Federal Environmental Assessment Review Process Guidelines Order, and tabling of Bill C-78, the Canadian Environmental Assessment Act (CEAA) on June 18 1990. The implications, for pipelines, of the continued application of the Guidelines Order and possible passage of CEAA into law, are discussed.

1.0 INTRODUCTION

The pipeline industry in Canada is in a quandary about how to approach development as a result of recent court interpretations of the 1984 Federal Environmental Assessment Review Process Guidelines Order (the Guidelines Order), and legislation tabled by the federal government on June 18 1990: Bill C-78, the Canadian Environmental Assessment Act (CEAA). The continued legal interpretation of the Guidelines Order has caused grave uncertainty about pipeline development in Canada due to approval delays, duplication of process, court challenges, and increased economic risks. The possible passage of the CEAA may or may not alleviate these concerns depending upon the interpretation of the Act, ministerial discretion, and the regulations which are to be promulgated under the Act. In this paper I discuss the implications of the existing situation and of the anticipated situation following passage of CEAA into law.

2.0 THE FEDERAL ENVIRONMENTAL PROCESS GUIDELINES ORDER

Background

The federal Environmental Assessment and Review Process (EARP) was initiated in 1974, adjusted in 1977, and formalized by an Order in Council in 1984 as the current Guidelines Order. The process is based on self-assessment, and was intended to be a flexible and informal means of advising the Environment Minister, and any Minister with decision making authority, on expected environmental impacts of proposed projects. The purpose was to ensure that the environmental implications of all project proposals are fully considered before irrevocable decisions are made. Projects with significant implications are to be referred to the Minister of Environment for public review by a panel

(Guidelines Order, Section 3).

However, since April 1989 the Federal Court and Federal court of Appeal have made a series of key decisions interpreting the Guidelines Order in relation to several projects including the Rafferty-Alameda and Oldman River dams:

* Mr. Justice Cullen (89-04-10): Canadian Wildlife Federation Inc. et al. v. Minister of the Environment and Saskatchewan Water Corporation (1989) 4 W.W.R. 526 (Fed. Ct.)

* Mr. Justice Jerome (89-08-11): Oldman River Society v. Ministers of Transport and Fisheries (1989) F.C.J. No. 904, Action No. T-865-89 (October 4, 1989)

* Mr. Justice Hugessen: Canadian Wildlife Federation Inc. v. Minister of the Environment and Saskatchewan Water Corporation (1989), 99 Nat. Rep. 72 (Fed. C.A.)

* Mr. Justice Muldoon (89-12-28): Canadian Wildlife Federation Inc. v. Canada (Minister of the Environment) and Saskatchewan Water Corporation (Intervenor)(1989), F.C.J. No. 1144 (T.D.), and .

* Mr. Justice Stone: Friends of the Old Man River Society v. Minister of Transport, and Minister of Fisheries and Oceans, and her Majesty the Queen in right of Alberta as represented by the Minister of Public Works (1990) Federal Court of Appeal, No. A-395-89.

Justice Cullen's decision of April 10 1989 interprets the Guidelines Order as carrying the full force of law. Thus all Ministers of the federal government must comply with the Guidelines Order when making decisions. Subsequent court decisions by Justices Jerome, Stone, Hugessen, Muldoon, and others variously interpreted the Guidelines Order in court case appeals. A significant result is that federal responsibilities are now so broadly interpreted that the federal government must consider the environmental impacts of all proposed actions in Canada that in any way fall under federal jurisdiction. Pipeline projects are placed in an uncertain situation since almost any activity undertaken in a provincial setting can be considered to affect some area of federal jurisdiction. Those pipelines approved just prior to the changed ruling could be retroactively shut down, and those pipelines following the ruling could be subject to an unpredictable approval process. The Guidelines Order could be applied to virtually all major resource developments and also to a variety of small projects normally requiring only local and provincial approvals. For example a modest intra-provincial pipeline expansion requiring the crossing of fish bearing streams, and thus subject to the federal Fisheries Act, could trigger an environmental assessment under the Guidelines Order.

Implications

The immediate implications to the pipeline industry are that all Ministers of the federal government must comply with the Guidelines Order when making decisions. Many departments could potentially be involved (Table I) but five departments/agencies with major impacts on the pipeline industry are the National Energy Board (NEB), Transport Canada , Department of Fisheries and Oceans (DFO), Indian and Northern Affairs Canada (INAC), and Environment Canada through the Canadian Wildlife Service (CWS). A brief summary of the implications of compliance with the Guidelines Order follows.

National Energy Board

One of the most important effects of the Rafferty-Alameda court decisions was that the NEB decided to conduct environmental screenings of all natural gas export applications. This action was precipitated by a Canadian Environmental Law Association application to the Governor in Council concerning compliance with the Guidelines Order and approval of Esso Resources Canada Limited's, Shell Canada Resources Ltd., and Gulf Canada Resources Ltd. Mackenzie Delta gas export applications. As a result the NEB implemented more rigorous screening criteria and assessment processes. Applicants for licences to export gas from Canada now face a standard requirement to consider the environmental effects of:

1. the construction of their pipeline

2. the production of hydrocarbons, and

3. the final use of hydrocarbons transported by their project.

Two implications of these new requirements are further exchange of information between applicants and the NEB, and licencing delays while environmental pre-screening is carried out for those export applications caught in the process change. Future applicants will likely face similar requirements to answer these questions. A list of activities which may be excluded from the screening process includes the Leave to Open Pipelines and oil and gas imports and exports (See Appendix I).

Transport Canada

Another major area of concern for pipelines is Navigable Waters Protection Act (NWPA) approval requirements for stream crossings. Approvals under the NWPA now require an environmental assessment before they are issued. Therefore, TC has implemented procedures to:

1. assess potential impacts on navigation, and
2. refer selected applications to other agencies for environmental screening eg. DFO for projects potentially affecting fish or fish habitat.

TABLE I: MAJOR FEDERAL DEPARTMENTS AND AGENCIES POTENTIALLY INVOLVED IN ADMINISTRATION OF THE PROPOSED CANADIAN ENVIRONMENTAL ASSESSMENT ACT (BILL C-78).

ATOMIC ENERGY CONTROL BOARD

CANADA OIL AND GAS LANDS ADMINISTRATION

CANADA NEWFOUNDLAND OFFSHORE PETROLEUM BOARD

CANADA NOVA SCOTIA OFFSHORE PETROLEUM BOARD

DEPARTMENT OF FISHERIES AND OECEAN

ENVIRONMENT CANADA
    -CANADIAN WILDLIFE SERVICE
    -ATMOSPHERIC ENVIRONMENT SERVICE

INDIAN AND NORTHERN AFFAIRS CANADA
    -YUKON AND NORTHWEST TERRITORIES WATER BOARDS

NATIONAL ENERGY BOARD

PARKS CANADA

TRANSPORT CANADA
    -CANADIAN COAST GUARD

TABLE II: PLANNED FEDERAL REGULATIONS RELATED TO THE CANADIAN ENVIRONMENTAL ASSESSMENT ACT (BILL C-78) FOR 1991

	---EXPECTED PUBLICATION---	
-----------REGULATIONS-------------	PART I	PART II
Environmental Assessment Procedures	4Q 1991	2Q 1992
Exclusion Lists	3Q 1991	4Q 1991
Mandatory Environmental Assessment Study List and Report	3Q 1991	4Q 1991
Regulatory Statutes Provisions List	3Q 1991	4Q 1991
Crown Corporations and Harbour Commissions	4Q 1991	2Q 1992
Indian Act Lands	4Q 1991	3Q 1992
Domestic Finacial Assistance	4Q 1991	2Q 1992
National Security	4Q 1991	2Q 1992
Projects Outside Canada	4Q 1991	2Q 1992
Offshore Boards	4Q 1991	2Q 1992
International Agreements	4Q 1991	3Q 1992
International Development	4Q 1991	3Q 1992

Source: Office of Privatization and Regulatory Affairs. 1990.

This process includes the development of a list of activities to be excluded from the environmental assessment process (See Appendix II). Unfortunately this list does not exclude pipeline crossings. The pipeline industry is still required to obtain an approval from Transport Canada for any pipeline which crosses a "navigable water". Section 5(1)(a) of the NWPA states that:

> "No work shall be built or placed in, on over, under, through or across any navigable water unless
>
> (a) the work and the site and plans thereof have been approved by the Minister, on such terms and conditions as the Minister deems fit, prior to commencement of construction;"

According to the Canadian Coast Guard (CCG) "Navigable Waters" includes any body of water capable in its natural state, of being navigated by floating vessels of any description for the purpose of transportation, recreation or commerce; it also includes a canal and any other body of water created or altered for public use as a result of the construction of any work, as well as any waterway where the public right of navigation exists by dedication of the waterway for public purposes, or by the public having acquired the right to navigate through long use." (Canadian Coast Guard 1980).

Although it is unlikely, the Minister may order the removal of any unapproved works under Section 6 of the NWPA. More importantly to the pipeline industry, every pipeline crossing of a "navigable water" in Canada is subject to these approval requirements. Any application for such an approval could lead to a full environmental assessment under CEAA. Individuals or groups who oppose projects could prevent construction of pipeline crossings or at the very least cause considerable delay in the issuance of approvals. There are literally thousands of pipeline crossings in Canada that have not been approved by Transport Canada and where the industry is vulnerable to wasteful and unnecessary environmental assessment reviews conducted only for the sake of preserving process. Proposals to amend the NWPA were made by Transport Canada in early 1990 and are expected to further restrict the scope of this Act to major projects that have a clear impact on the environment.

Department of Fisheries and Oceans

Department of Fisheries and Oceans environmental assessments could come about indirectly since referral of proposal with potential impact on fish or fish habitat would go to the DFO. Direct involvement of the DFO could also come about by means other than referral of applications or requests for authorizations as a result of Mr. Justice Stone's 1989 decision regarding the Oldman River Dam. He ruled that there are other means for a Minister to become aware of an initiative, undertaking or activity including direct requests on the part of individuals for specific action falling within the Minister's responsibilities. For example in the Oldman River Dam case a letter from the Friends of the Oldman River Society to the Minister of Fisheries and Oceans in August 1987 (Miller and Heggie 1990). Therefore DFO must comply with the Guidelines Order because the Minister has discretionary decision making authority under Sections 35 and 37 of the Fisheries Act. This means that DFO can not delegate decision making responsibilities to provincial authorities. Any provincial water licence or approval may therefore cause referral to DFO and can potentially lead to a full public hearing. DFO is presently receiving about twenty five thousand referrals per year which must be strictly reviewed according to the Guidelines Order process. Referrals may come from Transport Canada pursuant to the NWPA or any other jurisdiction with approval requirements for work in water courses. DFO is compelled to conduct such assessments even though DFO receives no applications or issues any licences or approvals.

Indian and Northern Affairs Canada

Indian and Northern Affairs Canada decided in May 1989 that each Northern Affairs Program (NAP) sector is responsible for implementation of the Guidelines Order in its area of responsibility. NAP must screen all projects involving:

- a federal initiative
- federal funding
- federal land (including Indian land) or
- an impact on an area of federal responsibility.

Federal departments are also to prepare an exclusion list under section 11(a) of the Guidelines Order. The purpose of the list is to streamline the screening process and to eliminate the need to screen actions which are environmentally benign or with impacts that can be routinely mitigated in a simple manner. The Federal Environmental Assessment Review Office (FEARO) principles and criteria for such lists are provided in Appendix III.

Indian and Northern Affairs Canada is one of the key initiating department for projects undertaken on federal lands in the Yukon and Northwest Terrritories and NAP administers the Guidelines Order for the regions. The respective Environment Conservation Division (ECD) administers this process with the assistance of a Regional Environmental Review Committee (RERC), an interdepartmental/intergovernmental body which provides advice and screening recommendations to ECD. The screening criteria are split into three levels:

Level I is performed by District and Regional Managers of the Water Resources and Land Resource divisons while administering existing legislation. The screening is based on information provided in applications for licences, permits, and leases and results in terms and conditions for environmental protection. The Technical Advisory Commitee (TAC) of the Northwest Territories Water Board performs this screening function for all licence applications and related submissions. Therefore pipeline projects involving stream crossings in the Northwest Territories could trigger the EARP process. Normally however, exploratory oil and gas drilling operations would most likely be affected at this level of review.

Level II screening is conducted by the RERC and would include for example oil and gas production facilities and pipelines, transboundary projects and projects generating significant public interest.

Level III screening corresponds to projects or activities with the potential for significant or unmitigable environmental effects.

Canadian Wildlife Service

The Canadian Wildlife Service mandate under the Migratory Birds Convention Act, raises concerns similar to those for DFO under the Fisheries Act. There is potential to trigger the environmental assessment process since pipeline projects can variously affect waterfowl indirectly through habitat alteration or directly through disturbance effects during construction or operation of compressor or pumping stations. The decision of Mr. Justice Stone in the appeal fo the Friends of the Old Man River Society regarding the Oldman River Dam, effectively expanded the scope of the Guidelines Order by confirming that the Guidelines Order requires the Minister of Fisheries and Oceans to comply with the process even though DFO considers no applications or approvals pursuant to the Fisheries Act and regulations. Therefore the Guidelines Order can act independently of other legislative requirements thus imposing requirements on agencies like the CWS to review environmental effects in their area of responsibility.

3.0 THE CANADIAN ENVIRONMENTAL ASSESSMENT ACT

Background

As a result of the court interpretations of the Guidelines Order considerable pressure was put on the Environment Minister to legislate the environmental assessment process. The government of Canada considered amending the Guidelines Order, to resolve the difficulties described above, but chose to draft new legislation instead. The process of amending the Guidelines Order was judged to take at least a year and require public consultation and legislative impact assessment which would have to be done again for introduction of new legislation which was already contemplated.

Legislating the assessment process was not a new idea. Process reform and modernization of the environmental assessment process began in 1985 with the Nielsen Task Force report, an exhaustive review of the regulatory regime and development of a Regulatory Reform Strategy by the Privy Council . CPA responded to these initiatives with several position papers and consistently opposed the legislation of the environmental assessment process (CPA 1986, 1986, 1987, 1988). However, the federal government pursued the legislation strategy following consultations and discussions with other governments, practioners, clients, and the public in 1987 and 1988 (Walsh et al. 1988). In 1988 the Federal Environmental Assessment Review Office (FEARO) prepared a Memorandum to Cabinet outlining necessary reforms and requesting permission to draft legislation. However, no Cabinet decision was made then because parliament prorogued and a general election was called. The initiative was started again in 1989 and Bill C-78 was introduced on June 18 1990, largely as a result of the Rafferty-Alameda court case decison on April 10, 1989. The Bill received first reading prior to summer recess of parliament. Before recess a House of Commons Special Committee to Pre-Study Bill C-78 was established (June 27) and submissions were invited from across Canada. The Canadian Petroleum Association made its submission to the Special committee on November 26, 1990 (CPA 1990).

Status

At the time of writing the Special Committee is still waiting for the tabling of government amendments to Bill C-78 and draft regulations listing the acts and regulations that will trigger the process (Regulatory Statutes Provisions List) and the lists of mandatory studies (Mandatory Study List). At least ten other sets of major regulations are planned for release in the coming year (Table II). The remaining tasks of the committee are to conduct a clause-by-clause examination of the Bill and report to the House of Commons. The draft Act would undergo third reading and debate in early fall. The draft regulations would likely be introduced in late May or early June when the consultation process on them would begin. After third reading the Bill would go to the Senate. Royal Assent and Proclamation of the Bill could occur in late December (Figure 1).

Thus far the Special Committee has received submissions and heard from thirty five witnesses and received approximately seventy five written briefs. The opposition parties have proposed at least one hundred amendments to Bill C-78 and the Cabinet is considering a package of 60 amendments. All the provincial and territorial environment ministers of Canada except Quebec have proposed ten amendments to the Bill for consideration (CCME 1990). These amendments are primarily concerned with means to permit the federal minister to transfer responsibility for assessment to a province (Amendment H), and to establish an intergovernmental cooperative scoping process for identification of federal provincial participation levels where there are overlapping jurisdictions (Amendment G). The CPA suppported these proposed amendments and sent a letter to the Special Committee on December 10, 1990 reiterating our position that duplication between federal and provincial environmental assessment processes.

Implications

There is considerable uncertainty about the ultimate content of the Act and the consequent regulations. Therefore the expected implications of CEAA are also uncertain. However the major implications of the Act in its present form for pipeline developments, can be generally anticipated. The major steps in the reformed process are shown in Figure 2.

Federal Implementation Process

Canadian Environmental Assessment Act

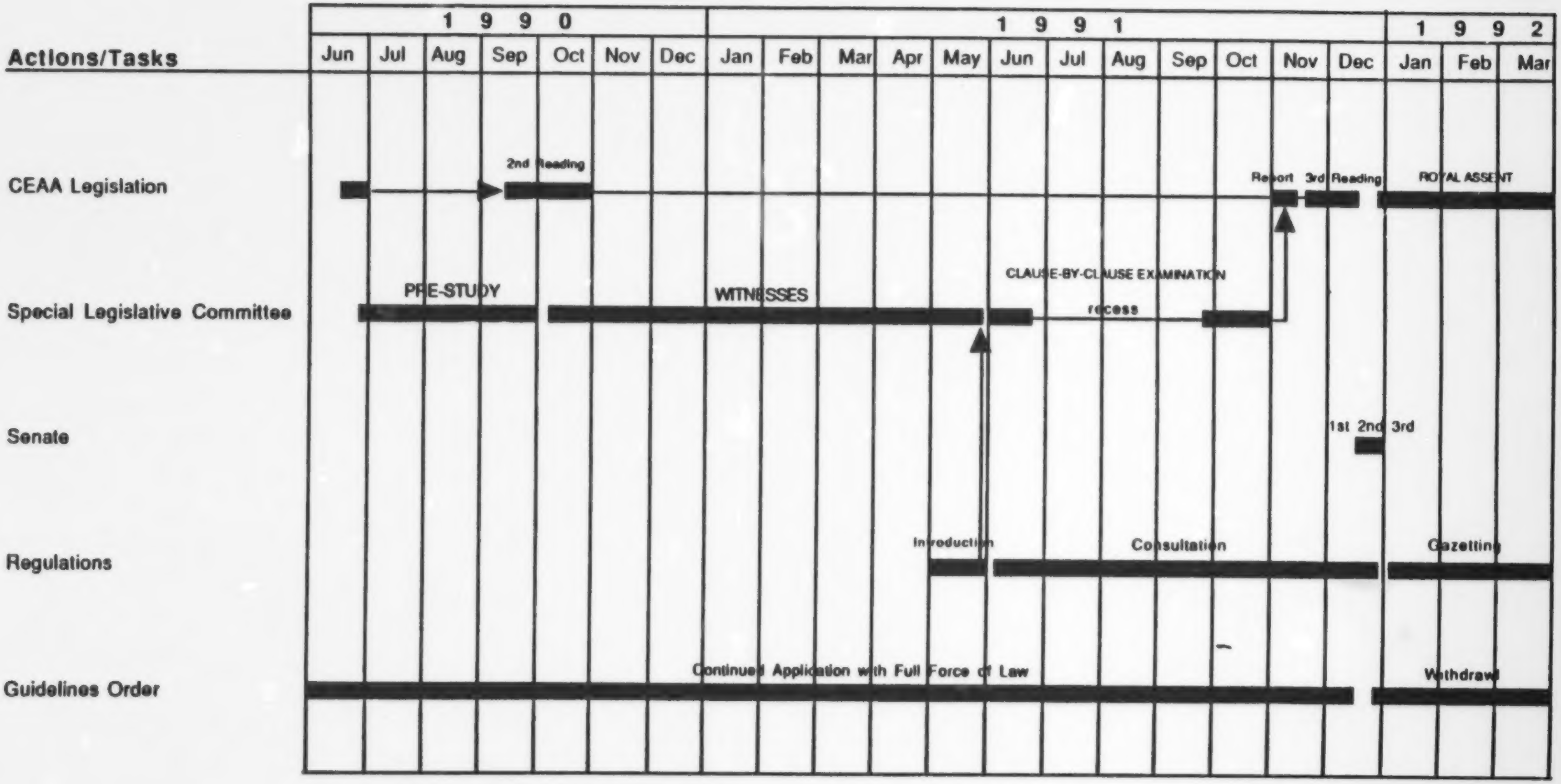

FIGURE 1: ANTICIPATED FEDERAL IMPLEMENTATION PROCESS FOR THE PROPOSED CANADIAN ENVIRONMENTAL ACT (BILL C-78) MAY 16, 1991.

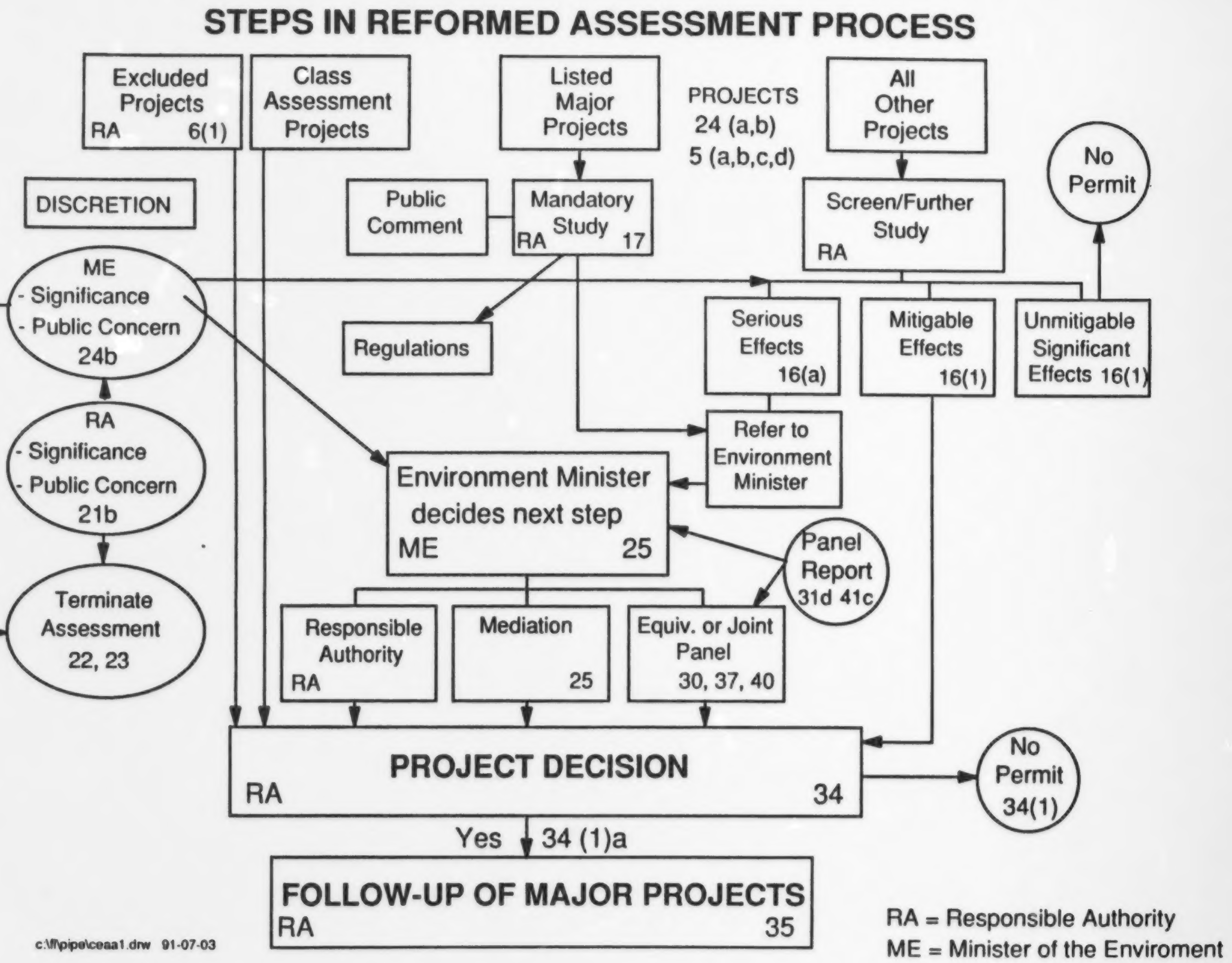
STEPS IN REFORMED ASSESSMENT PROCESS
Excluded Projects RA 6(1)
Class Assessment Projects
Listed Major Projects
PROJECTS 24 (a,b) 5 (a,b,c,d)
All Other Projects
DISCRETION
Public Comment
Mandatory Study RA 17
Screen/Further Study RA
No Permit
ME - Significance - Public Concern 24b
Regulations
Serious Effects 16(a)
Mitigable Effects 16(1)
Unmitigable Significant Effects 16(1)
RA - Significance - Public Concern 21b
Refer to Environment Minister
Environment Minister decides next step ME 25
Panel Report 31d 41c
Terminate Assessment 22, 23
Responsible Authority RA
Mediation 25
Equiv. or Joint Panel 30, 37, 40
PROJECT DECISION RA 34
No Permit 34(1)
Yes
34 (1)a
FOLLOW-UP OF MAJOR PROJECTS RA 35
RA = Responsible Authority
ME = Minister of the Enviroment
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FIGURE 2: STEPS IN THE PROPOSED CANADIAN ENVIRONMENTAL ASSESSMENT ACT ASSESSMENT PROCESS IN RELATION TO MAJOR SECTIONS OF THE ACT.

Ostensibly, the Act will clarify confusion surrounding the application of the current Guidelines Order. However, the requirements for the pipeline industry under the new Act will virtually be as broad as the existing Guidelines Order. This means that many of the issues currently facing the industry will continue albeit with greater certainty. There will likely be:

* continued regulatory duplication of process between federal agencies such as the NEB, and between federal and provincial/territorial agencies such as the proposed Canadian Environmental Assessment Agency, and Alberta's Energy Resources Conservation Board, and the territorial Water Boards. CEAA in its present form allows the substitution of process but not decision making. FEARO is attempting to address duplication by establishing regional committees on environmental assessment in each region. There already exists a Northern Regulatory Regime committee and regional committees on environmental assessment in all the provinces.

* Environmental screening of projects will continue by the responsible authority. Projects which are routine, repetitive and of insignificant environmental impact may be treated as class assessments. Screening for cumulative impacts and sustainable development principles will be difficult.

* Regulations will determine how the Act is applied Exclusion and Mandatory Study lists are already being developed by regulatory authorities such as NEB, Transport Canada, Northwest Territories Water Board, and DFO. Such lists will have critical effects on the pipeline industry.

* A mediation option will be available and should provide more flexibility to resolve environmental issues and reduce unnecessary public reviews. Public review panels will continue as the main means of assessing project impacts. The process would provide for subpoena powers of witnesses and information

* A proliferation of substitute and joint environmental panels especially with provinces. However, it is still unclear how this process will work for provincial agencies. A court case currently in front of the Supreme court of Canada concerning the legality of the Guidelines Order should clarify this issue. The decision is expected this summer.

4.0 CONCLUSION

Court interpretations of the Guidelines Order have irrevocably changed the process of environmental assessment in Canada. These changes are a stricter ongoing interpretation of the Guidelines Order, in a unintended manner, and the introduction of a legislated environmental assessment process under Bill C-78 (CEAA). The implications of these changes for the pipeline industry are occurring now in response to the continued legal interpretation of the Guidelines Order. Both governments and industry have adapted to these changes in the short term but the result is increased social costs due to federal-provincial/federal-federal duplications of effort, increased administration requirements, process inefficiencies, approval delays, confusion, uncertainty, and frustration. The proposed CEAA may or may not resolve these problems and increase certainty about the process depending on the application of the Act through regulations and administration procedures.

Conceivably the Act could still be passed by December 1991 depending on the government and public will. In the meantime, industry must continue to comply with the Guidelines Order until withdrawal after the passage of replacement legislation, or amendment of the existing Guidelines Order. Pipeline developers should provide the most complete information available when making applications, allow more time for approvals and use multiple contacts to facilitate the process. They should continue to cooperate with regulatory agency screening processes to expedite approvals and work with industry associations such as CPA to support expeditious resolution of the existing situation. CPA believes that Bill C-78 must go forward quickly and must resolve the present uncertainties by taking into account industry concerns. The clear challenge to all levels of government is to implement environmental approval processes that will reduce or eliminate duplication and fragmentation and alow the orderly and environmentally acceptable development of Canadian petroleum resources. The challenge to industry is to continue to work within the existing system while continuing to to take full advantage to participate in all opportunities to for consultation on the Act and regulations in the coming months.

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APPENDIX I: NATIONAL ENERGY BOARD EXCLUSION LIST PURSUANT TO ENVIRONMENTAL ASSESSMENT AND REVIEW PROCESS GUIDELINES ORDER, APRIL 30, 1991.

April 1991

National Energy Board
List of Automatic Exclusions
Pursuant to EARP Guidelines Order

General Principles

1. Issues related to the technical aspects of and need for a project are assessed by the Board independently of its environmental review. Those issues thus would not normally be considered as part of the Board's environmental assessment.

2. Despite a project's designation of automatic exclusion, the Board may, as a result of potentially significant environmental or public concern, determine that screening of a particular project would be necessary.

Reference	Title	Description	Comments
Part I	**National Energy Board**	Establishes the Board and describes its powers.	Automatic Exclusion (Except Section 21)
Section 21	Review, etc. of decisions and Orders	Authority of the Board to review decisions, rehear applications or amend orders, certificates etc.	Screening Required
Part II	**Advisory Functions**	Responsibility of the Board to advise the Minister on energy issues.	Automatic Exclusion
Part III	**Certificates of Public Convenience and Necessity**	Procedures for the authorization of pipeline and power line construction.	
Section 47	Leave to Open Pipelines	Requirement for Board approval to begin operating a pipeline.	Automatic Exclusion
Section 56	Revocation and Suspension	Authority to revoke certificates in cases of non-compliance.	Automatic Exclusion
Section 58	Exemptions	Authority for the Board to exempt certain pipelines or associated facilities from certain provisions of the NEB Act.	See Note 1

(B) Automatic exclusion for applications for natural gas exports, imports, exports for subsequent import and imports for subsequent export authorized:

(i) by order*;

(ii) by licence** where the development of new facilities for production, processing, storage or transmission would not be required.

(Screening would be required for applications for gas export licences where the development of new facilities for production, processing, storage or transmission would be required).

Note 4

Automatic exclusion for those applications for border accommodation electricity exports.

---

* Orders apply to:

(a) exports or imports of gas for a period not exceeding 2 years;

(b) exports or imports of not more than 30 thousand cubic metres of gas per day, for a period exceeding 2 years but not exceeding 20 years; and

(c) exports of gas for subsequent import or imports of gas for subsequent export, for a period not exceeding 25 years.

** Licences apply to all exports and imports of gas not authorized by order.

Reference	Title	Description	Comments
Part VII	Interprovincial Oil and Gas Trade	Authority of the Board to assume the supervision and control of the movement of designated oil or gas out of a designated province or area.	Automatic Exclusion (Except Sections 125-127)
Sections 125-126	Issue of Licences	Authority to issue licences for the movement of designated oil or gas.	Screening Required
Section 127	Regulations	Authority to make regulations re: designated oil or gas.	Screening Required
Part VIII	General	Other general matters.	
Section 129	Regulations	Authority to make regulations concerning accounting procedures.	Automatic Exclusion

APPENDIX II: CANADIAN COAST GUARD EXCLUSION LIST PURSUANT TO ENVIRONMENTAL ASSESSMENT AND REVIEW PROCESS GUIDELINES ORDER, SEPTEMBER 1, 1991.

NAVIGABLE WATERS PROTECTION ACT

EARP GUIDELINES ORDER

EXCLUSION LIST

EXCERPT FROM THE

NWP DIVISION OPERATIONAL DIRECTIVE

NAVIGABLE WATERS PROTECTION ACT (NWPA)

GUIDELINES FOR THE APPLICATION OF THE ENVIRONMENTAL REVIEW PROCESS

SEPTEMBER 1, 1990

J. Bourassa
NWP Programs Division
Canadian Coast Guard
Transport Canada

(613) 998-1415

2.10 AUTOMATIC EXCLUSION LIST FOR NWPA APPLICATIONS AND ENQUIRIES

2.10.1 A project (work) for which a NWPA approval is required, or an activity such as an enquiry may be excluded from EARP if it meets the criteria provided in the NWP Programs Division exclusion list, which is described in the following paragraphs.

2.10.2 Notwithstanding the criteria set out within, an enquiry or application for approval may still be subject to EARP if in the judgement of the responsible manager, the enquiry or application for approval has the potential to cause harmful environmental effects.

2.10.3 This exclusion list does not include any project of activity which falls into any of the following categories:

- The project or activity significantly and adversely affects historical, archaeological, unique or endangered features of the environment;
- The project or activity has cumulative impact potential;
- The project or activity, on the basis of public reaction to similar past projects or activities, or the manager's knowledge of the local situation, has substantial potential on the basis of environmental impact for public reaction or concern.

2.10.4 THE FOLLOWING ACTIVITIES OR PROJECTS ARE EXCLUDED FROM THE ENVIRONMENTAL ASSESSMENT AND REVIEW PROCESS:

2.10.4.1 All maintenance and repairs, rebuilding or alterations to existing structures provided that such proposals:

- use standard design criteria (including those previously approved) and there is no other reason to believe that adverse environmental effects will result;
- do not take place in any area designated as environmentally sensitive or archaeologically protected;
- are not located within a provincial park;

.../2

- are not beyond the international boundary line;
- do not use banned substances or materials as components on the existing structure.

2.10.4.2 All written and verbal enquiries including requests for an opinion on whether a waterway is navigable or non-navigable at a specific site.

2.10.4.3 All applicable exclusions and class assessments listed in the Coast Guard EAFP Policy. April 1, 1990.

2.10.4.4 All minor works which are synonymous with cottage, residential or recreational construction; (e.g. boathouses, docks, floats, launching ramps, rafts, slalom courses, swimming areas, waterski jumps, wharves and water intakes). DOES NOT INCLUDE STORM SEWER OR EFFLUENT OUTFALL PIPES.

2.10.4.5 All minor works such as landing stages, launching ramps, ramps, marine railways, pilings, slipways, cribwork and dolphins where there is little or no disturbance to the bed of the waterway.

2.10.4.6 Minor construction, repairs or maintenance of shoreline protection such as breastwork, retaining walls and rip rap.

2.10.4.7 The installation of submarine cables crossing navigable waterways where there is neither trenching nor where there is little or no disturbance to the bed of the waterway. Submarine cables include telephone cables and electrical power distribution cables of 30K volts or less.

2.10.4.8 The installation of overhead telephone lines and electrical power distribution cables of 30KV or less. (DOES NOT INCLUDE MAJOR TRANSMISSION LINE CROSSINGS OR CORRIDORS).

2.10.4.9 Modes of transportation to sites (by vehicle, boat, helicopter or fixed-wing aircraft), method of obtaining site data (e.g. measurements, hydrographic soundings) and monitoring of projects by NWP officers.

2.10.4.10 Emergency operations which must proceed without delay for reasons of public safety or security or for the public good (e.g. the immediate replacement of a bridge or electrical power/telephone line or cable, which has been destroyed by storm action or by some other unforeseen event).

.../3

2.10.4.11 Minor revisions to works approved under NWPA where the change is not considered significant enough to issue a revised approval or exemption document (e.g. minor reconfiguration of floating docks within the scope of the originally approved work).

2.10.4.12 Letters of authorization for temporary works or activities where no significant impacts to the environment have been previously identified.

APPENDIX III: FEDERAL ENVIRONMENTAL ASSESSMENT REVIEW OFFICE EXCLUSION LISTS PRINCIPLES AND CRITERIA.

1. Purpose

Exclusion lists identify physical works or activities which are known to have no direct or indirect effect or a negligible effect on the environment and do not, therefore, require an environmental assessment. The aim is to avoid the expenditure of time and money on assessing projects which are inherently benign from an environmetal standpoint, thereby enabling resources to be focussed on the assessment of projects which do have an impact on the environment.

2. Approach

Projects are identified on the basis of the results of previous screening decisions which have determined that environmental impacts are noexistant or negligible, or using a set of criteria. Entries are placed under generic headings wherever possible, to avoid having a very long and unmanageable list, and are classified and edited within each subgrouping.

The lists are reviewed periodically to ascertain whether additional classes of projects should be added on the basis of screenings, and whether certain types should be removed. At any time, projects meeting exclusion list criteria may, under certain circumstances, be subject to screening. This situation can occur when it becomes apparent that adverse environmental effects may result.

4. Parameters

These are set by definitions in the proposed Canadian Environmental Assessment Act. The project or activity should be a physical work involving:

(i) a construction
(ii) an operation
(iii) a modification
(iv) a decommissioning
(v) an abandonment

5. Criteria

Some basic criteria for compiling exclusion lists can be identified. Generally the intrinsic characteristics of a project on a exclusion list are such that it does not involve the following:

(i) land disturbance
(ii) ecological disturbance
(iii) effect on groundwater or waterbody
(iv) emissions of noxious gas or liquids
(v) noise emissions
(vi) use or production of toxic or hazardous substances
(vii) ionising or other hazardous radiation
(viii) contributes to adverse cumulative impacts
(ix) potential for significant public reaction or concern
(x)benign impact at present but risk of future adverse environmental impact

CPA 1991 PIPELINE CONFERENCE
SARNIA-MONTREAL PIPELINE - WHAT NEXT?

May 15-16, 1991
Calgary, Alberta

as presented by P.D. Daniel
Vice President, Planning
Interprovincial Pipe Line Inc.

<SLIDE> (LOGO)

Good afternoon ladies and gentlemen. It is my pleasure to be able to address this conference today on the subject of IPL's Sarnia to Montreal Pipeline. For those of you who attended this conference last year, this subject will sound strangely familiar. I am going to try not to be too repetitive and will try to address recent significant changes on the line and likely future activity.

The Sarnia to Montreal line has been in operation since 1976 and its operation has been extensively discussed and studied by IPL and other interested parties. Most recently the NEB completed a study for the federal Minister of Energy, involving input from all interested parties.

<SLIDE> (AGENDA)

This afternoon I will give you some background on the Sarnia to Montreal pipeline, talk about recent developments since August, 1990, update you on the current status of the line, discuss potential future uses, and explain IPL's position on some of the issues that this line is currently facing.

<SLIDE> (MAP)

The Sarnia to Montreal pipeline is 520 miles long, originating in Sarnia, Ontario and has been used to deliver light, medium, and heavy crude oils to Montreal area refineries, as well as crudes to the export market off the east coast. It became operational in the spring of

1976 after a lengthy National Energy Board approval process and a difficult, compressed construction period. Let me briefly go back to the time of the facilities application.

<SLIDE> POINT 1

That facilities application was filed with the National Energy Board in March, 1974. That was the first time IPL was required to include an environmental report as part of the application requirements. At the time the NEB had not yet formalized its newly developed environmental guidelines.

<SLIDE> POINT 2

In 1974 the markets this line would serve were not clearly quantified. Although forecasts of the day supported a demand of 250,000 bpd of western Canadian crude into the Montreal market, these volumes could not be secured by throughput commitments from the Montreal refineries. However, IPL was prepared to proceed with the pipeline application with encouragement from the federal government. Well into the NEB hearing process and five months after the facilities application was filed, serious concerns were beginning to arise about the industry forecasts being used to support the application.

<SLIDE> POINT 3

Ultimately the hearing was adjourned until the NEB revised its long range outlook for western Canadian supply. The study verified IPL's concerns that there could be insufficient western Canadian supplies to meet the crude oil demands west of the Ottawa valley as well as the Montreal market area. Not surprisingly, these western Canadian supply concerns are with us again today.

<SLIDE> POINT 4

Due to the questionable supply available, IPL needed some form of financial guarantee before it could proceed with the construction of this line. This was ultimately provided by the federal department of Energy, Mines & Resources in the form of a "deficiency agreement", which obliges the federal government to "make up the shortfall whenever the operating revenue in a given year fails to meet the fixed and variable costs of the extension". This agreement expires in 1996.

<SLIDE> (PICTURE)

Construction began on this line in September, 1975, after a long and difficult public review process, and it was operational in 1976. The line was constructed during the winter of 1975/1976 under very difficult weather conditions. These conditions led to later concerns on the technical viability of the line for NGL service, and to one of its many controversies.

I would now like to move on to the operation of the line and its throughput history.

<SLIDE> (ACTUAL THROUGHPUT)

Crude oil was first delivered to Montreal in 1976 at a rate of 84,000 bpd; peaking at 300,000 bpd in 1980. Since then, volumes have fluctuated but have followed a declining trend. In 1989 IPL moved about 105,000 bpd of crude from Sarnia through to Montreal. Volumes steadily declined through the line as Montreal refiners chose increasingly to source their crudes from offshore. Why has this decline occurred? Well there are several reasons, which I would like to briefly discuss.

The first reason is the overall light crude supply situation to Ontario and PADD II and the demand for Canadian crude oil in Montreal. Let's look at that supply situation.

<SLIDE> (ONTARIO AND PADD II)

To help you get oriented, this map shows the PADD districts in relation to the Great Lakes, Ontario, and Quebec. Ontario and PADD II are considered in aggregate in this exercise as they are both landlocked and are both served by the same crude transportation networks; namely, pipelines from Western Canada and the Gulf Coast.

<SLIDE> (ONTARIO/PADD II - LIGHT CRUDE SUPPLY/DEMAND)

This area graph illustrates the forecast for crude oil supply to the Ontario and PADD II regions. The downward trend of domestic supply and the increasing wedge of imports is a continuation of the trend of earlier years which led to the discontinuance of Line 9 operation. As you can see from the attached, the Canadian light and equivalent supply is expected to further decline from 700,000 BPD in 1991 even with the assumption of new synthetic supply; similarly, PADD II light production in the U.S. continues its decline, as do PADD III and PADD IV lights available to PADD II. With Montreal being the most eastwardly delivery point for this crude, this decline in North American light supply was obviously felt there first.

<SLIDE> CRUDE OIL PRICING

A second crude oil sourcing factor which effects the operation of the Sarnia to Montreal line relates to the relative prices of crude oils delivered to Montreal. The primary competing crudes being Canadian crude and North Sea Brent crude. Brent crude is on a general trend to becoming more favourably priced in Montreal than western Canadian crude. Brent is cheaper during the summer months, and over the last few years, Brent crude has been cheaper for longer periods of time. The gap between the two crude prices is also increasing. In 1989, Brent crude averaged 20 cents per barrel lower than western Canadian crude, and was $2.40 less in June, 1989. In early 1990, Brent averaged about 25 cents cheaper per barrel, and was $2.00 less than western Canadian crude in March. This trend was temporarily upset from August onward into 1991 due to the supply concerns associated with the Iraqi war.

<SLIDE> TRANSIT TIME

In addition to declining supply of Western Canadian light crude and an increasing price differential, transit time from source to Montreal is also an important consideration of refiners taking delivery at Montreal. A barrel of Brent crude from the North Sea can be delivered to Montreal ten to thirty days faster than a barrel of western Canadian crude leaving Edmonton at the same time, assuming a throughput of 100,000 bpd on the Sarnia-Montreal pipeline.

So for those general reasons we have seen a decline in the use of the Sarnia to Montreal pipeline for west to east crude movements.

Let's now look at some recent developments.

<SLIDE> (RECENT DEVELOPMENT) POINT 1

In September 1990, nominations dropped very rapidly primarily due to the general trends and reasons indicated earlier, but also because the costs of carrying the linefill were becoming increasingly onerous for the remaining shippers.

Shippers are responsible for providing the linefill on the Sarnia-Montreal pipeline as they are on all of IPL's system. That linefill totals 2.3 million barrels and at $20, represents a significant inventory to have tied up for weeks during delivery. Shippers indicated a desire to discontinue use of the line in the fall of 1990.

<SLIDE> POINT 2

However, because this was happening during the Iraqi war and at a time when there was concern over security of supply, shippers were encouraged to keep the line in East-West operation through the 90-91 heating season and the Iraqi war. This appeal came directly from the Minister of Energy.

<SLIDE> POINT 3

The Minister also requested the NEB to conduct a study on the line to help determine ultimate disposition and use. This study was conducted in early 1991 by the NEB and gave industry, governments and associations an opportunity to express their opinions on the current and future use of the line.

<SLIDE) POINT 4

In March of 1991 with the Iraqi war over, and the heating season basically behind us, the shipper indicated no further nominations to Montreal and a desire to have their linefill delivered to Montreal.

<SLIDE> POINT 5

That purging process is currently underway with approximately one-half of the line now evacuated and the full project to be complete by the third week of June.

<SLIDE> POINT 6

IPL next intends to apply for long term deactivation of the line, assuming no further nominations for its use are made. That application will probably be made this fall, as soon as it appears as though the line will not be used for a period of one year.

However, Line 9 does not appear to be dead yet. IPL has had requests to consider reversing the line to bring offshore crude into Ontario to supply the developing light crude shortfall. IPL has also considered converting the line to natural gas service, which is technically feasible. So the question is, what is next for Line 9?

Let's take a brief look at these alternatives and then I will give you IPL's position at this time.

<SLIDE> (REVERSAL)

Firstly, let's look at reversal. The need for reversal is currently being considered by industry and IPL expects to receive a formal request from a group of Ontario refiners to make application to the NEB to reverse the line by 1994.

<SLIDE> (FORECAST SCENARIOS)

This rather busy graph illustrates a range of timeframes over which we expect that reversal may become viable. The green area represents the declining supply of domestic crude; the colored segments on top of that are the pipeline capacities up from the U.S. gulf coast. Therefore, the top of the orange line represents the available supply of crude to Ontario and PADD II. The white line indicates the demand, which grows at .2% per year. From this forecast, a shortfall of crude would be expected by 1997, as indicated by the "Expected Case" line. If one were to use the NEB light supply forecast and CPA heavy forecast, labelled here as the low supply case, that shortfall moves back to 1996. If one assumes that the Chicago refiners bid a higher percentage of Canadian light crude away from Ontario refiners, that shortfall could move forward to as early as 1994. If again, one takes seasonal shortfalls into account, the need may be as early as 1992.

As you can see, forecasts are not definitive with regard to the timing of the need for reversal, however, there is full agreement that offshore light crude will eventually make its way into Ontario.

A second alternative for the Sarnia-Montreal pipeline is conversion to natural gas service.

<SLIDE> (CONVERT TO GAS)

With the current need for additional natural gas delivery facilities to Ontario, Quebec and the U.S. northeast, conversion would appear to make sense. In fact IPL has had approaches from interested parties and the markets are there. IPL has evaluated the technical feasibility of converting the line to natural gas service and it is feasible. This may come as a surprise to those of you who followed the Soligaz project. Conversion of the line to NGL service was ruled out due to the high costs of replacing sections of the line to bring it up to NGL pressure specs. However, the natural gas operation would be at a lower pressure and would therefore not require the same level of capital expenditures or pose the same safety concerns. Natural gas can be economically transported through the line at lower pressures whereas NGL could not.

A third alternative for the line is to simply deactivate and idle it.

<SLIDE> IDLE

Although this may be a reasonable short term solution, in the long term it's not very practical. Someone would have to bear the ongoing operating costs of the line and depreciation, which are currently estimated at about $20MM; after 1996 those costs would be reduced to approximately $10MM per year. At present, under integrated tolling and the deficiency agreement, that someone is the shipper on the Canadian Main System; under standalone tolling and before 1996, that someone would be the Canadian government; after 1996 under standalone tolling that someone is IPL. And that leads me into IPL's position with regard to future use of the line.

<SLIDE> POINT 1

Our view is not unlike what we expect the NEB study to reveal: that market forces should prevail. In other words, if an economical case could be made to reverse, convert or continue the lines operation, that should occur. However, IPL does not want to see the asset sit idle. Although idling has no negative financial impact on IPL now, it would have after the deficiency agreement expires in 1996.

<SLIDE> POINT 2

Assuming a continuance of the integrated tolling methodology, an active line will obviously have some benefits to all shippers on the IPL system compared to a deactivated line. Any revenue generated would help reduce the remaining revenue requirement of the system.

Similarly, under reversal at sufficiently high volumes, the revenue generated would contribute to lowering the toll on the main system. Under these circumstances, shippers on the main system would be better off under an integrated tolling methodology.

<SLIDE> POINT 3

Because IPL believes that 'economics should prevail' we feel that the tolling methodology of the line must be determined once and for all - for all modes of operation. IPL intends to request the NEB to expand its consideration of the tolling methodology at our next Class 3 hearing to include not only the current mode of operation but also deactivation and reversal. Only when this methodology is known can economics actually be allowed to take their course. Indications are that the NEB would be willing to consider the tolling methodology for reversal prior to the filing of a reversal application.

<SLIDE> POINT 4

If industry support is received, IPL could apply for reversal as early as the summer of 1991. Assuming that integrated tolling is approved, IPL forecasts reversal of the line in the 1994 timeframe.

If standalone tolling is approved, reversal may still be economic compared to alternate transportation routes from the U.S. Gulf Coast to Chicago. One way or another, that offshore crude will be required and will be economic in Ontario, assuming the continuing growth and overhang of light crude production on a global basis.

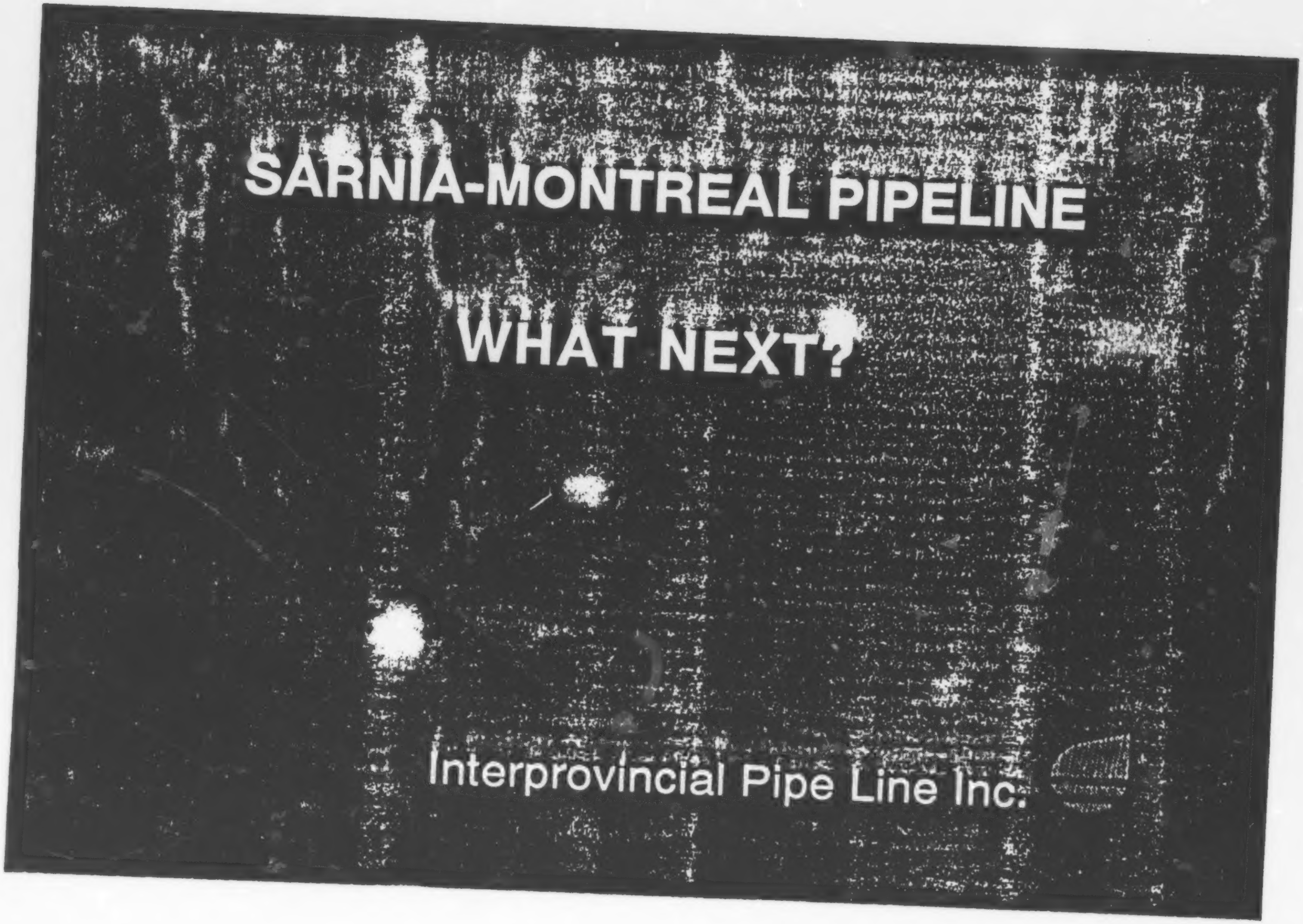
<SLIDE> POINT 5

If reversal of Line 9 is not economic for whatever reason, IPL stands to suffer significant operating losses beginning in 1996. Our intention obviously would be to avoid that situation and to seek alternate uses for the line.

<SLIDE> LOGO

In conclusion, Line 9 has had a fascinating history including an aborted initial hearing, a difficult construction, a role as a key link in Canada's crude transportation system, the subject of a Minister's study, and now deactivation. The most interesting times and best opportunities may be yet to come.

That concludes my talk. I would be pleased to try to answer any questions.



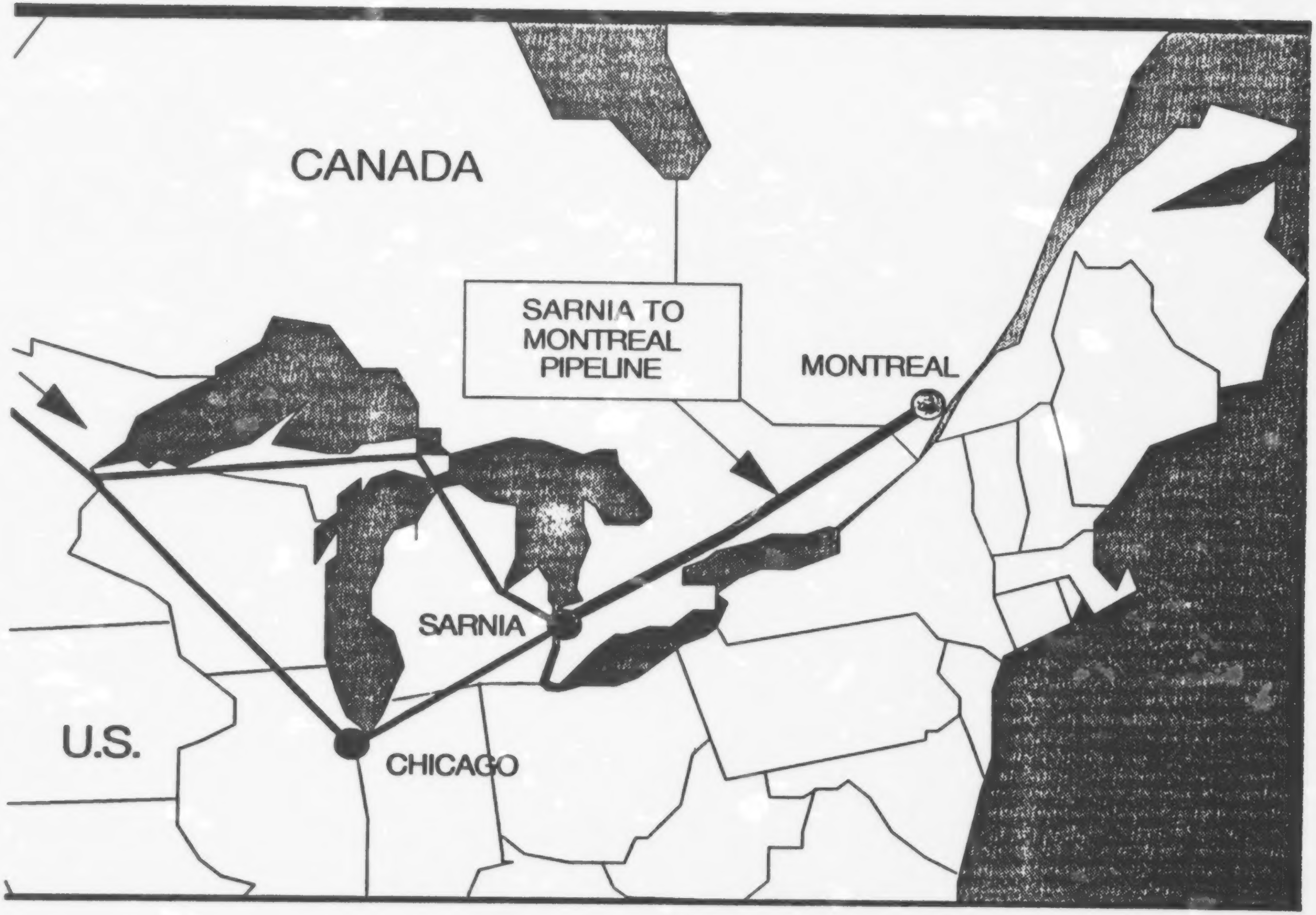
SARNIA-MONTREAL PIPELINE

WHAT NEXT?

Interprovincial Pipe Line Inc.

OUTLINE

1. Background
2. Recent Developments
3. Current Status
4. Potential Future Use
5. IPL's Position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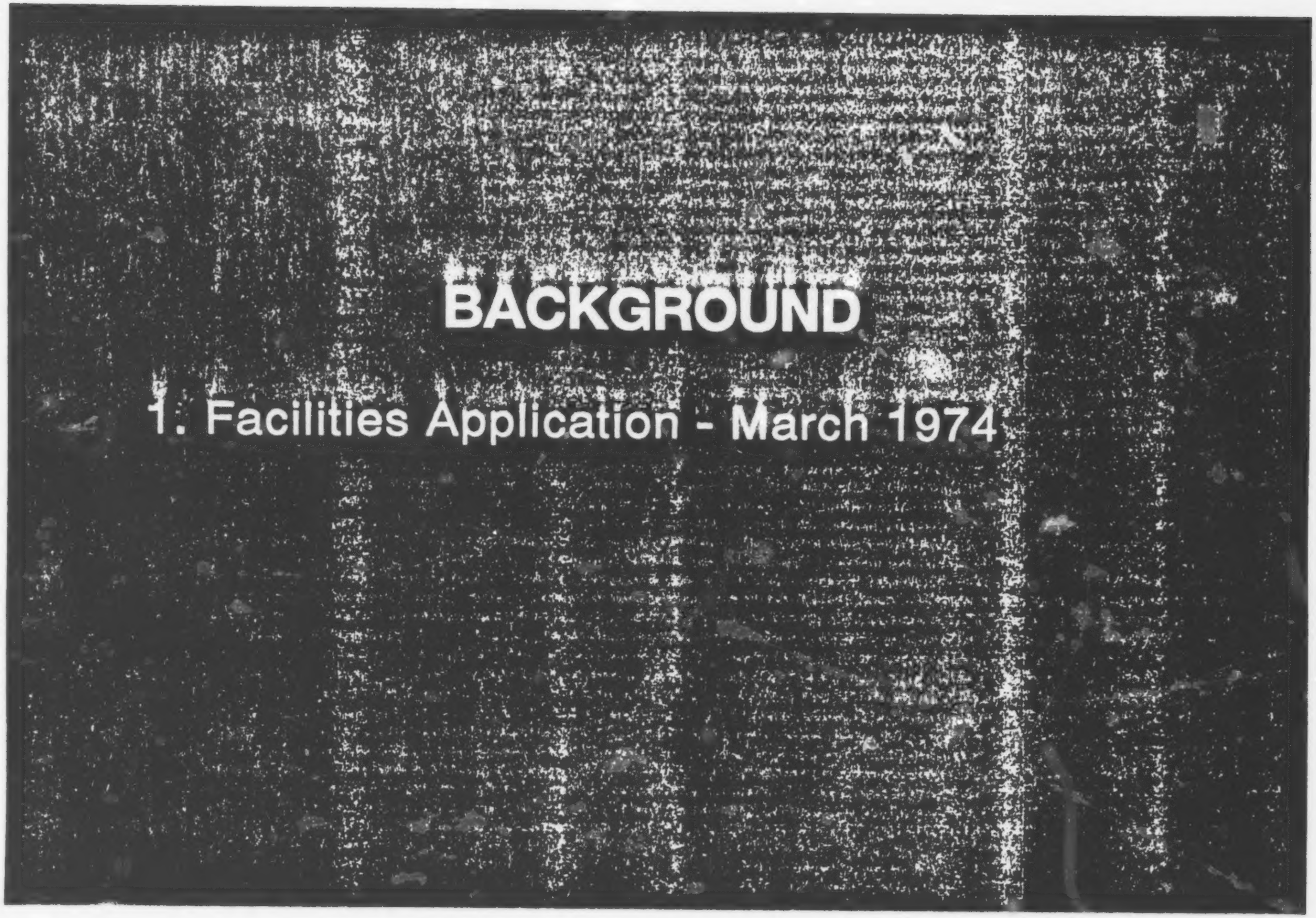
SARNIA TO
MONTREAL
PIPELINE
MONTREAL
SARNIA
U.S.
CHICAGO



BACKGROUND

1. Facilities Application - March 1974

BACKGROUND

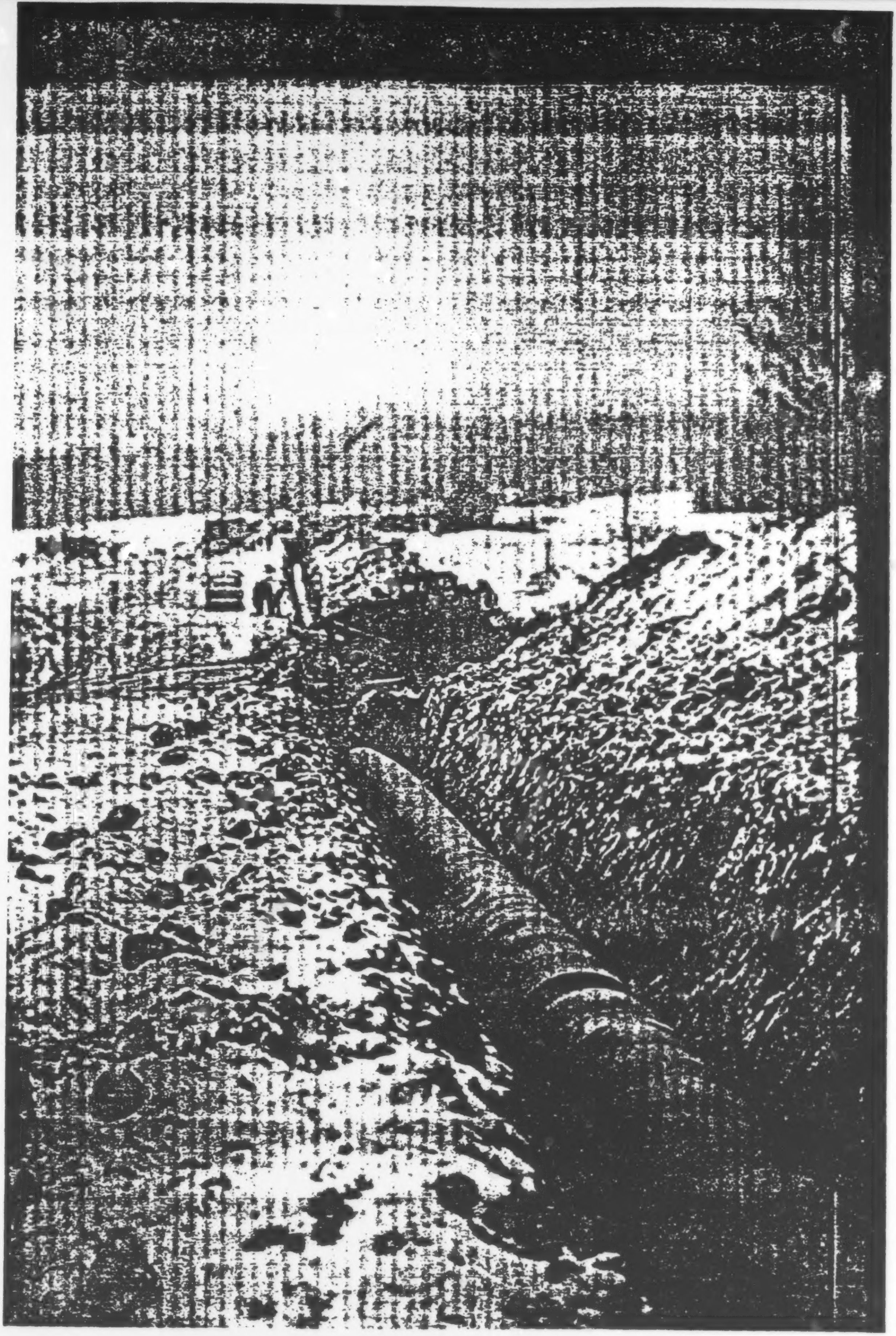
1. Facilities Application - March 1974
2. Market Need Not Well Defined

BACKGROUND

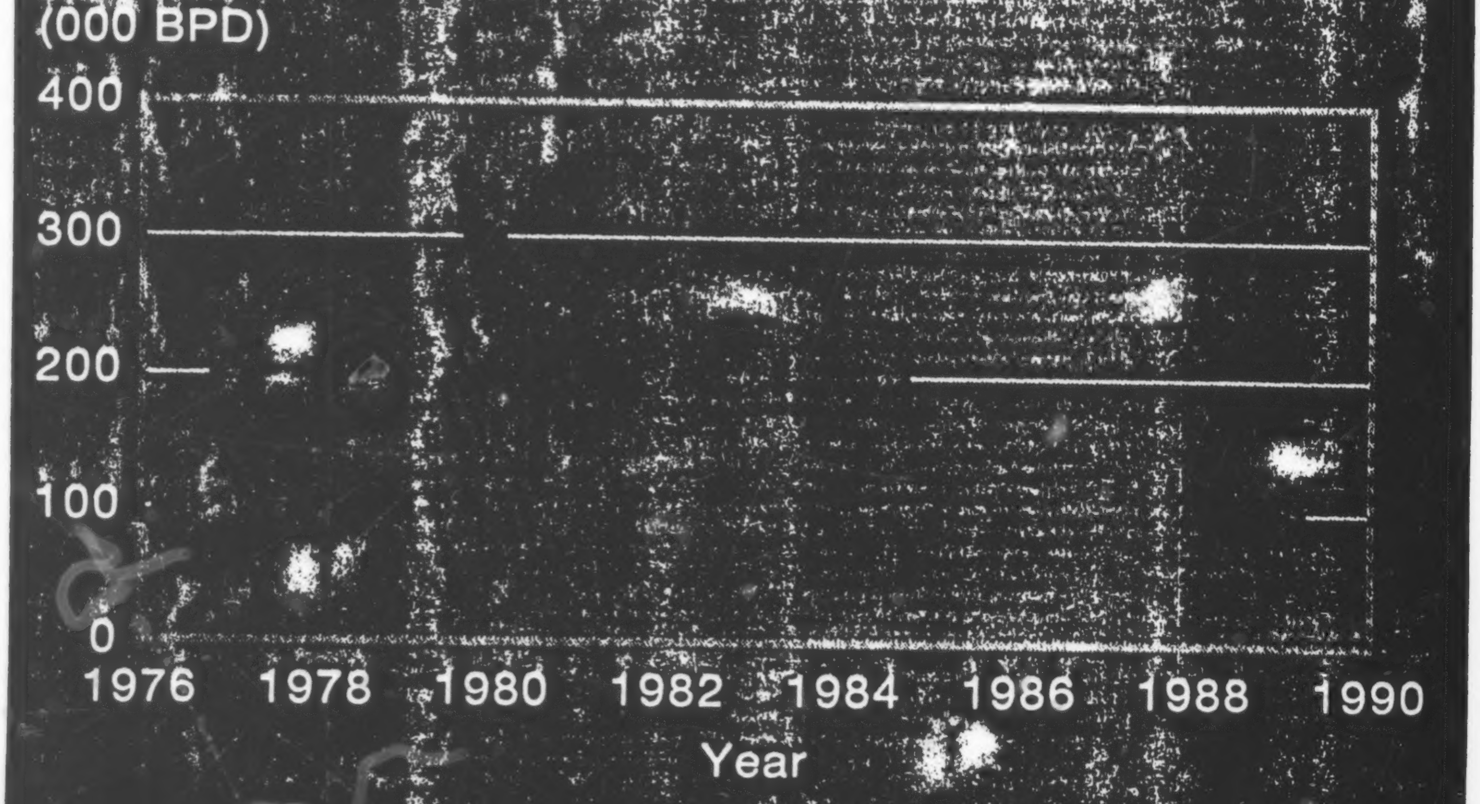
1. Facilities Application - March 1974
2. Market Need Not Well Defined
3. Hearing Adjourned

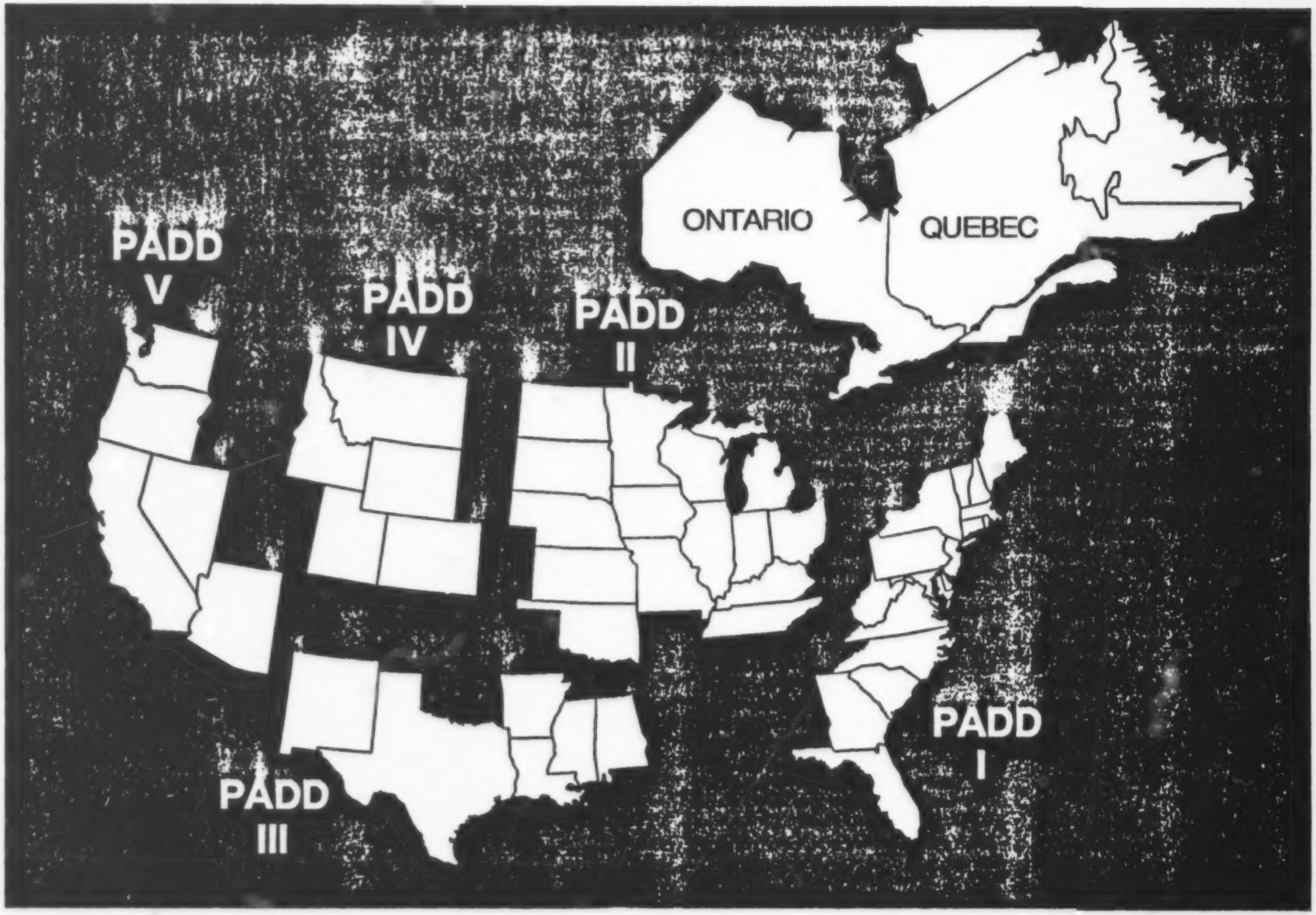
BACKGROUND

1. Facilities Application - March 1974
2. Market Need Not Well Defined
3. Hearing Adjourned
4. Government Support - Security Of Supply

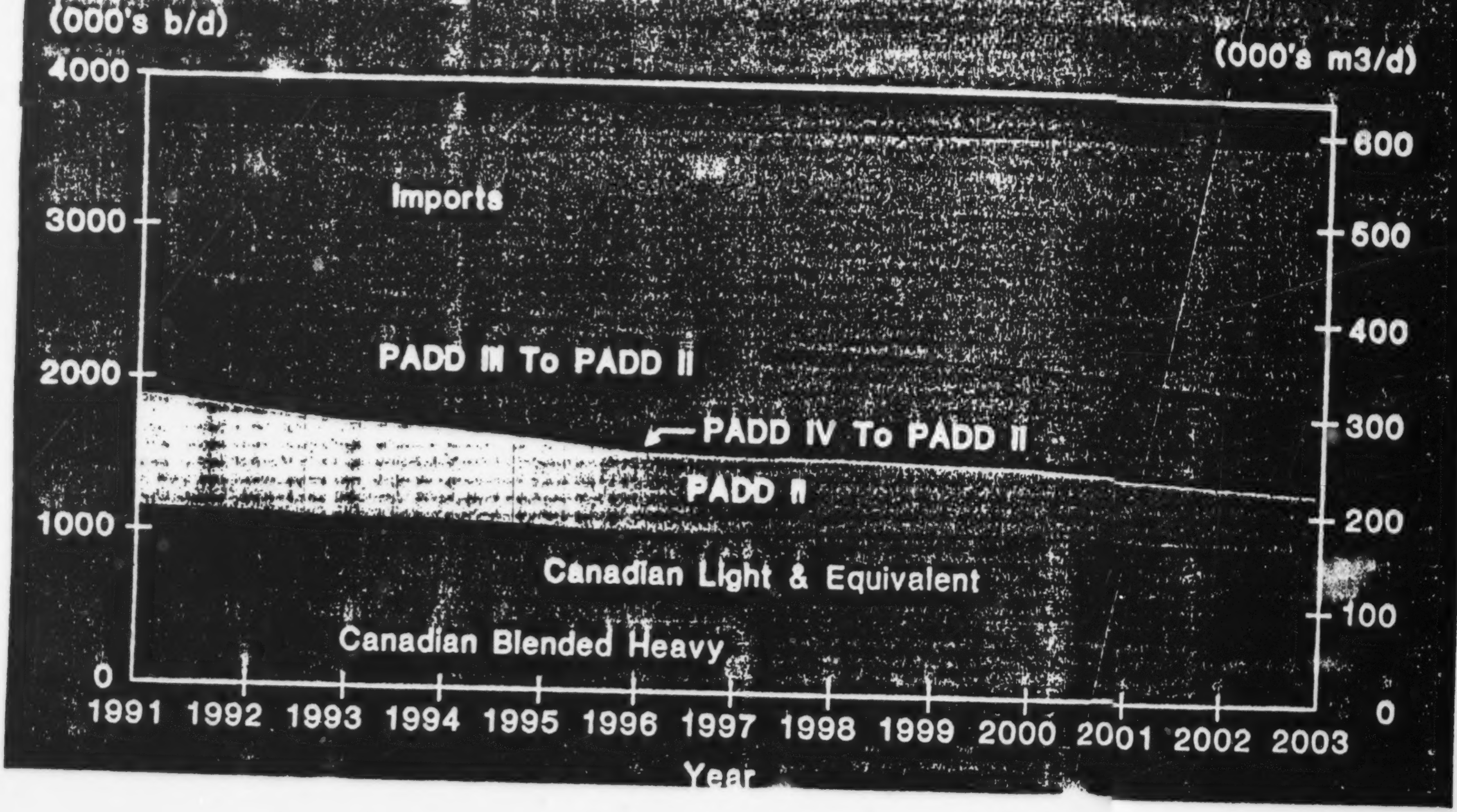


ACTUAL THROUGHPUT



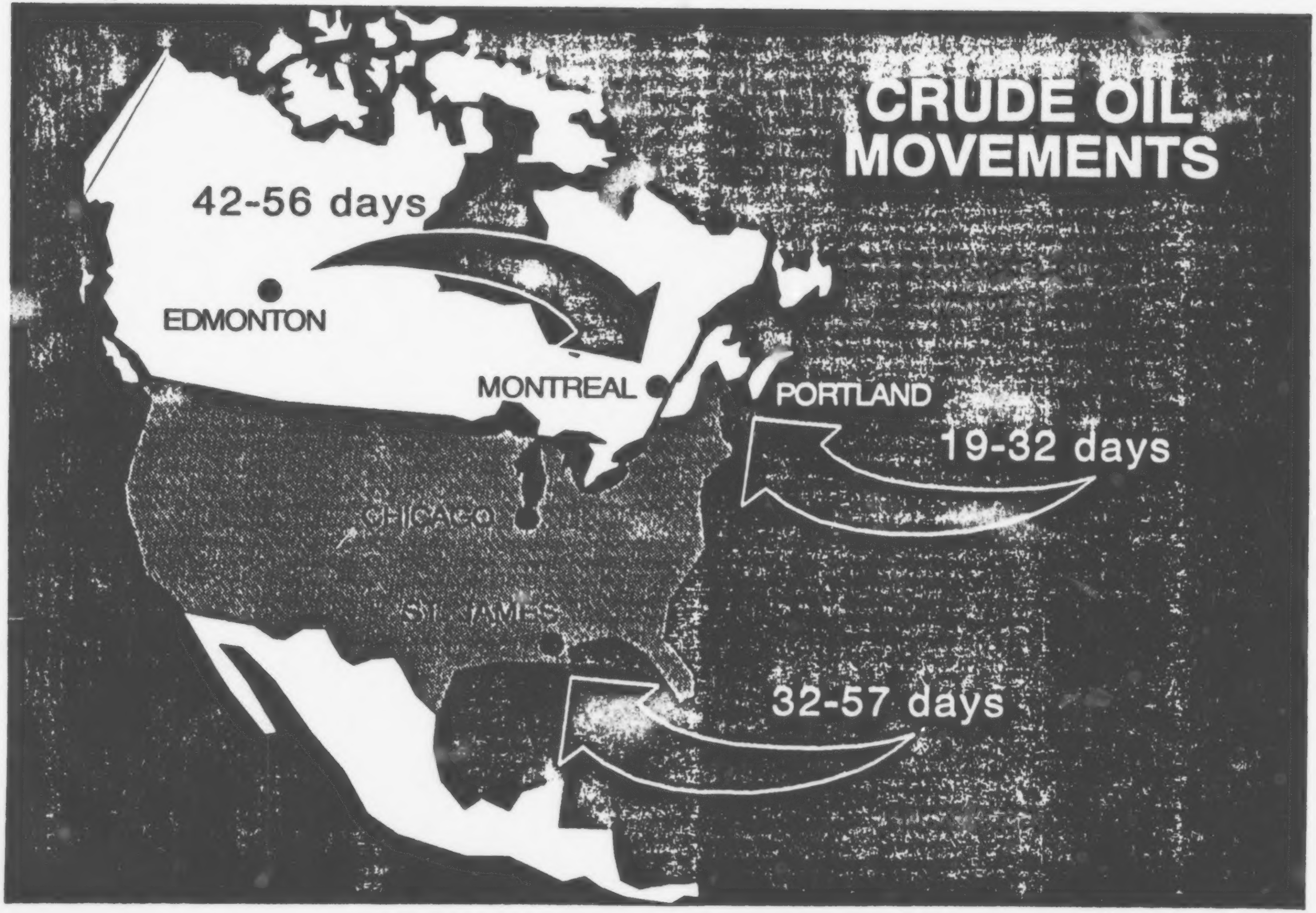

ONTARIO
QUEBEC
PADD V
PADD IV
PADD II
PADD III
PADD I

ONTARIO & PADD II SUPPLY



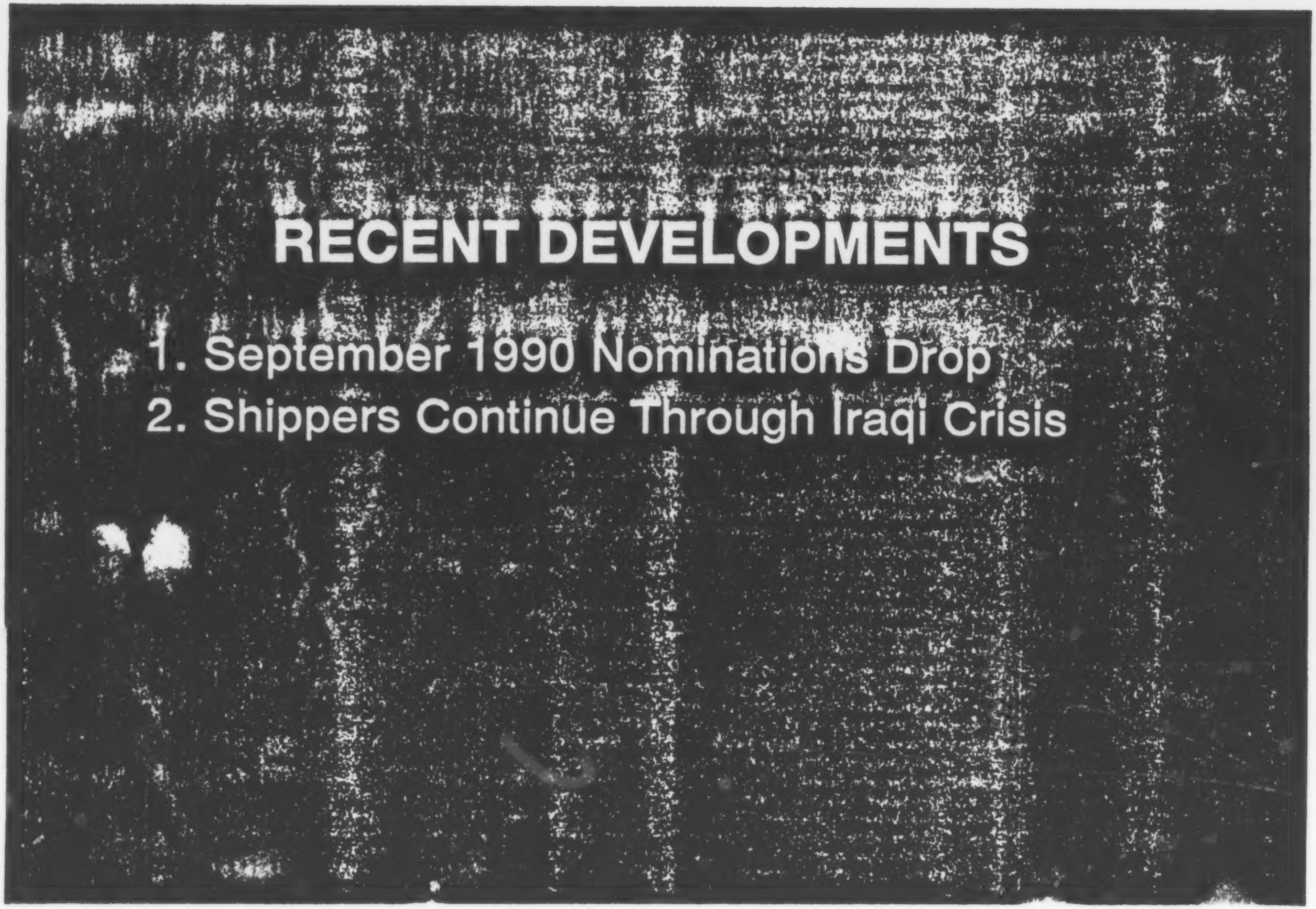
CRUDE OIL PRICING

CRUDE OIL MOVEMENTS


42-56 days
EDMONTON
MONTREAL
PORTLAND
19-32 days
CHICAGO
ST. JAMES
32-57 days

RECENT DEVELOPMENTS

1. September 1990 Nominations Drop



RECENT DEVELOPMENTS

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2. Shippers Continue Through Iraqi Crisis

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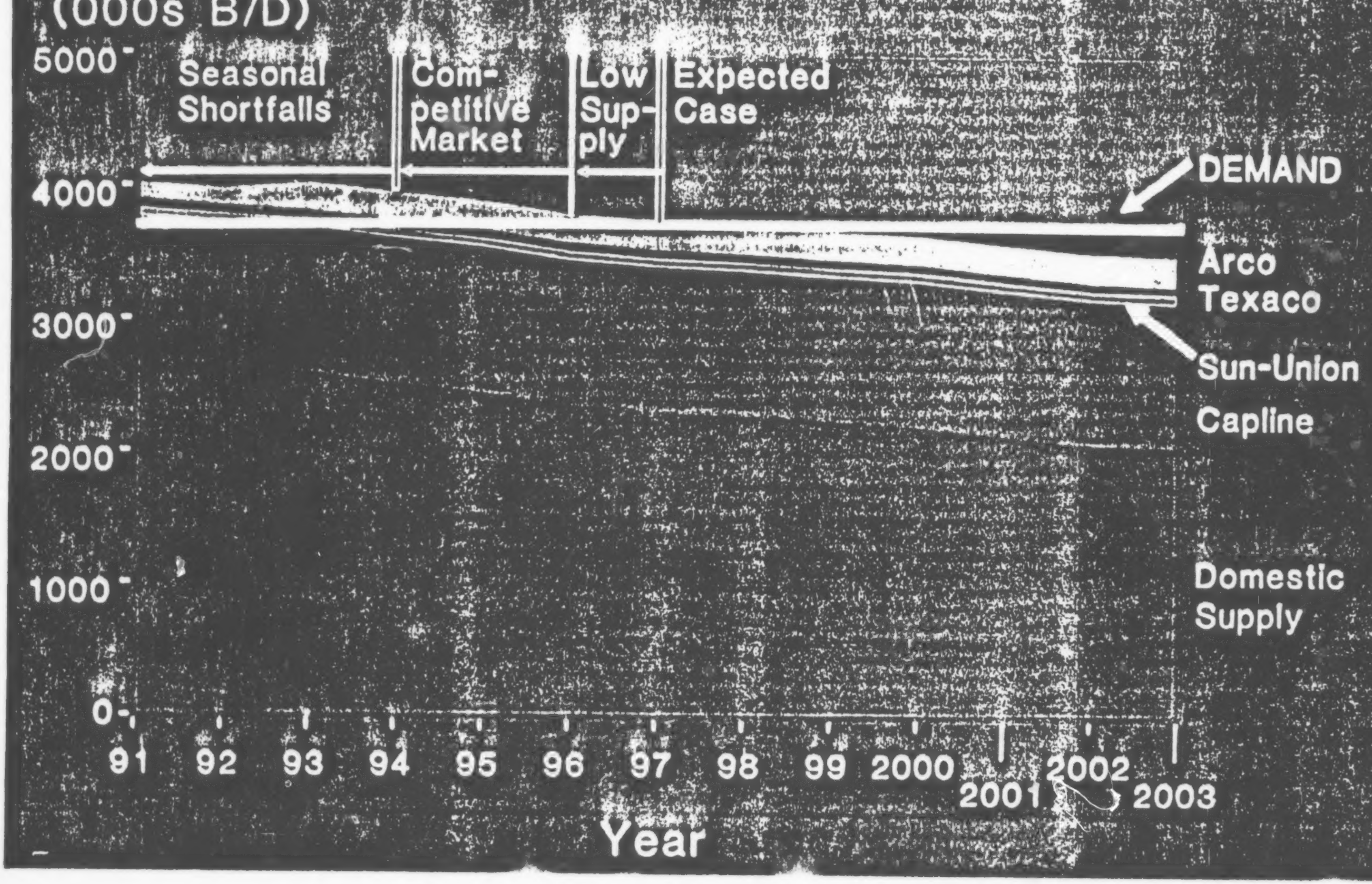
3. NEB Study Commissioned Early 1991
4. Shipper Requests Linefill March 1991
5. Purging Underway
6. Deactivation Application Being Considered

PIPELINE SUPPLY LOGISTICS



ALTERNATIVES

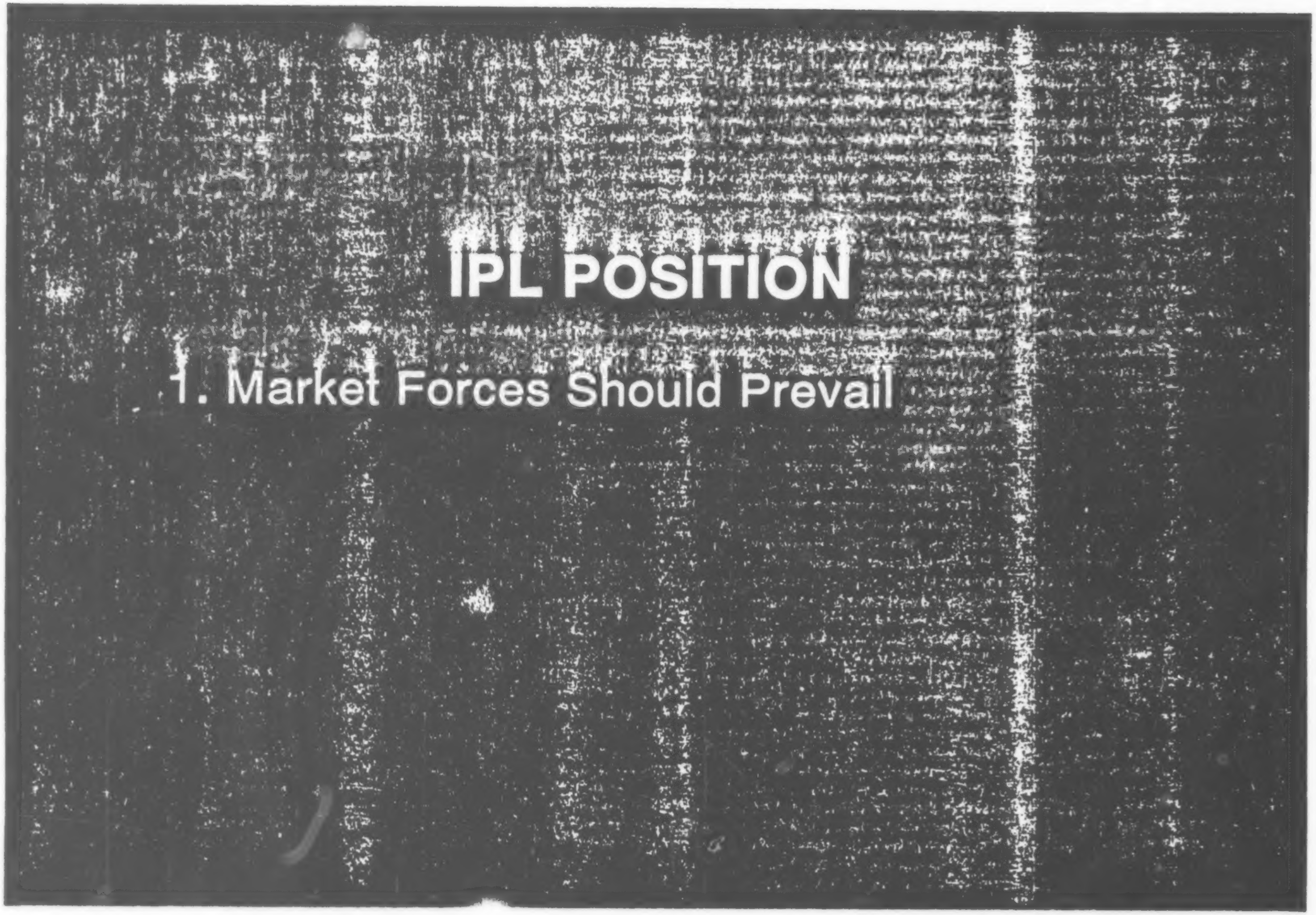
1. Reversal

ALTERNATIVES

1. Reversal
2. Convert To Gas

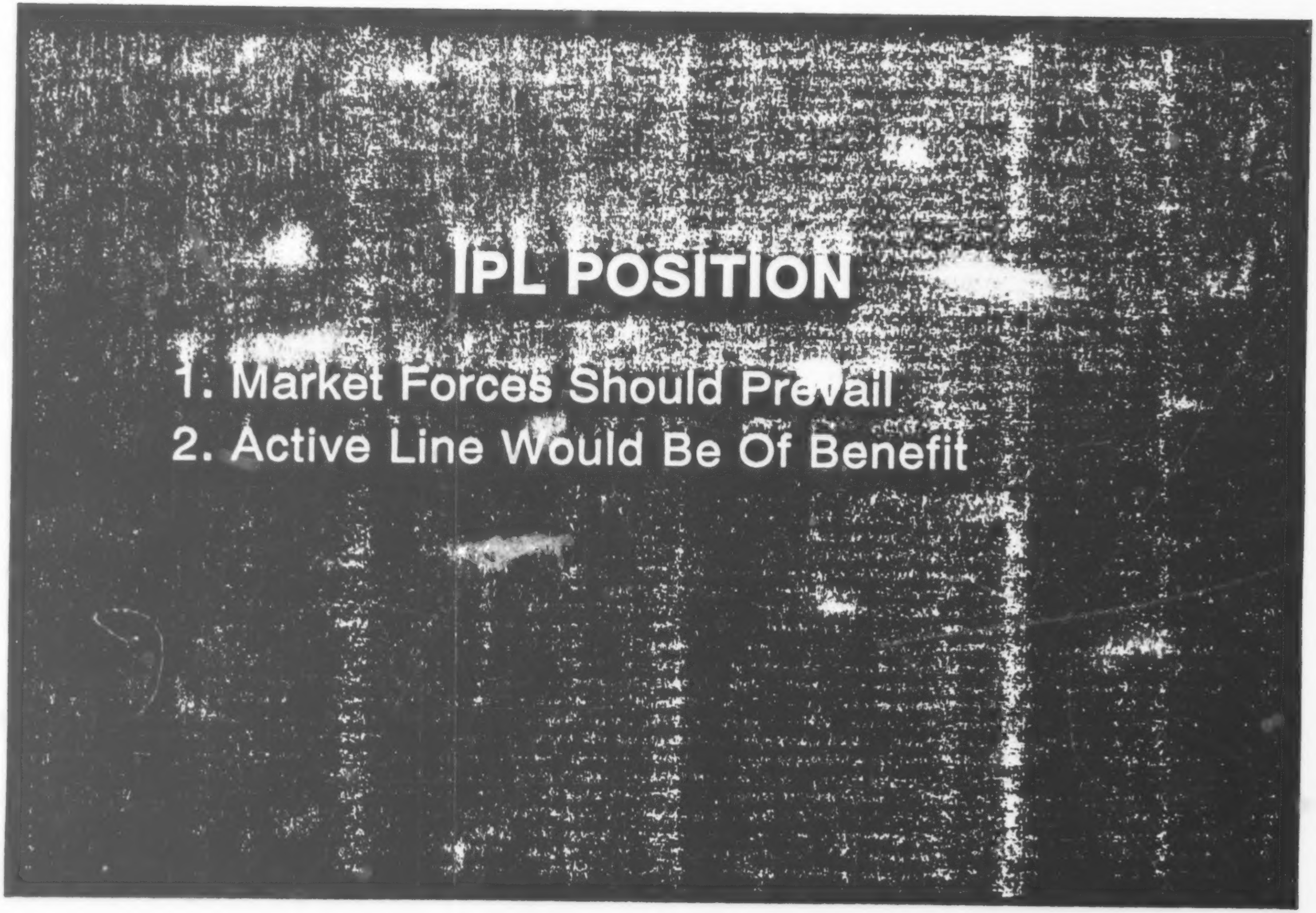
ALTERNATIVES

1. Reversal
2. Convert To Gas
3. Deactivate & Idle



IPL POSITION

1. Market Forces Should Prevail



IPL POSITION

1. Market Forces Should Prevail
2. Active Line Would Be Of Benefit

IPL POSITION

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2. Active Line Would Be Of Benefit
3. Tolling Methodology Should Be "Set"

IPL POSITION

1. Market Forces Should Prevail
2. Active Line Would Be Of Benefit
3. Tolling Methodology Should Be "Set"
4. Apply For Reversal If Industry Supports

IPL POSITION

1. Market Forces Should Prevail
2. Active Line Would Be Of Benefit
3. Tolling Methodology Should Be "Set"
4. Apply For Reversal If Industry Supports
5. Actively Pursue Other Alternatives